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QUANTITATIVE EVALUATION OF SUSTAINABLE ENERGY PATHWAYS FOR COLORADO'S POWER SECTOR: FOCUS ON GREENHOUSE GAS MITIGATIONS

by

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Quantitative Evaluation of Sustainable Energy Pathways for Colorado's Power Sector: Focus on Greenhouse Gas Mitigation

Thesis directed by Professor Anu Ramaswami

ABSTRACT

This thesis develops a Colorado specific model to depict the evolution of statewide electric power sector, evaluating various scenarios for environmental and economic sustainability, with focus on greenhouse gas mitigation. This model simultaneously evaluates interactions between the various climate action regulations, current power infrastructures, future advanced technologies, limits of renewable energy and demand-side-management (DSM). For this purpose, a MARKAL optimization model and database is developed that minimizes total system costs while maximizing environmental benefits within transmission and other system constraints.

The objectives of the thesis were:

1) Database Development & Calibration: To develop a Colorado-specific (CO-MARKAL) database for power sector representing Business-as-Usual (BAU) for 30 years planning horizon (2005-2035), calibrated to 2005 Energy Information Administration State Electricity Profiles data;

2) Development of Model: Including model refinements for 1) Finer Time-Slices (peak hour representation) suitable for Colorado power generation landscape with sizeable amount of natural gas combustion turbines; 2) Renewable Portfolio Standards Rule-Based constraints; 3) Aggregated DSM and Energy Efficiency measures to represent citywide actions and evaluate statewide Energy Efficiency impacts.

3) Future Scenario Evaluation: The four scenarios studied were:

- Advanced emerging technologies incorporating carbon-capture and sequestration (CCS) technology: Pulverized Coal with 50% CCS, Coal IGCC with 50% CCS, Gas IGCC with 90% CCS, Advanced Combustion Turbine & Combined Cycle, and Advanced Nuclear Technology.

- Energy Efficiency scenario, including linkage of citywide actions with statewide system to achieve 300 GWh per year and 1% per year reduction in energy consumption
- Regulatory Policy scenario evaluating both CO_2 caps consistent with the Colorado Climate Action Plan, and CO_2 taxes applied both upstream as Btu tax (cents per million Btu) and downstream (dollar per ton of CO_2 in production of electricity)
- Sensitivity scenarios, including energy demand forecasts, natural gas price volatility, and demand elasticity were also evaluated for the various scenarios.

Model output showed the following results relevant for future planning and policy-making decision for Colorado power sector:

- Aggressive DSM and Energy Efficiency (DSM/EE) scenario was the most favorable scenario with societal gain of achieving over 7% CO_2 reduction from BAU, with economic savings from avoided infrastructure investments of at least $9 Billion (2005$) over a 30 year planning horizon. However, the carbon emissions from DSM/EE scenario alone did not meet any of the CO_2 caps goals.
- Regulations that cap CO_2 at 1990 levels in 2035 resulted in a system cost of around $7 Billion (2005$) above BAU costs, and were slightly lower (by 11%) than costs incurred by capping CO_2 at 2005 levels in 2020.
- Btu taxes (upstream) did not have much impact on CO_2 mitigation because they were uniformly applied to all fossil-fueled generation. CO_2 taxes (downstream) did not make much of impact in CO_2 mitigation because of constrained wind power in the system (at 30% of production by 2035). Removing the constraints, the system became sensitive to the downstream CO_2 tax at $60/mt. Carbon taxes were the most expensive options costing the system from $8 to $21 Billion (2005$), above BAU costs, over the planning horizon depending on the amount of tax.

Sensitivity analysis indicated that Colorado Power Sector is at high risk to future carbon regulations, possible increases in natural gas prices, and future growth, suggesting that mandates for considering sizeable renewable energy and energy efficiency are needed immediately.

This abstract accurately represents the content of the candidate's thesis. I recommend its publication.

Signed [redacted]

Anu Ramaswami

DEDICATION

I dedicate this thesis to my family who encouraged and inspired me to continue my goal of completing this work. To my wife Shahnaz, an exceptionally talented architect and artist with great passion for arts and sciences and love for the environment, who has devoted much concentration on zero-emission building design; to my daughter Michelle, who as a young physician has a great appreciation for the environment and the ecosystem and climate change issues; and last but not least to my youngest daughter Krystle, who as a young physicist has already gotten involved with ground-breaking research that will soon help the mankind to cope with dreadful diseases.

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TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

PREFACE

There is widespread scientific consensus that global warming is occurring and poses serious risk of adverse climate change from growing greenhouse gas emissions — in particular carbon dioxide (CO2). Climate change is a long-term global problem and its economic and environmental impacts on society may take many years to develop fully. Certain countries have begun to adopt CO2 mitigation policies to comply with the Kyoto Protocol. In the United States, some states and regions have begun to adopt CO2 mitigation policies in order to stay current with possible future global CO2 market and mandatory CO2 regulatory regime. Such early action mitigation policies allow states, regions, and power companies to adjust gradually to changing economic conditions that may arise from carbon mitigation policies. However, most states — including Colorado — lack the tools needed to assess the tradeoff between economic costs and society gains from emission reduction required for sustainable energy planning.

In 2004, Colorado voters passed Amendment 37 creating a Renewable Energy Standard (RES) for the State, which required 10% of regulated utilities retail energy be produced from renewable energy resources. In 2006, the Colorado legislature passed new laws that encouraged the development of integrated gasification combined-cycle generation. In 2007, new bills were passed that doubled the amount of RES to 20% for regulated utilities and added a 10% requirement for non-regulated utilities (Cooperatives and Municipalities). This bill also encouraged the development of new transmission infrastructure to support the development of new renewable energy resources and established energy efficiency and Demand-Side Management (DSM) goals for the regulated utilities. Also in 2007, The Governor of Colorado announced a statewide plan to reduce CO2 emissions by 20% from 2005 actual emission levels by 2020 and 80% by 2050.

These new legislative actions in Colorado have created challenges for both the regulators and the utilities. Most significantly, the new legislation has replaced earlier "least-cost" and "fuel neutrality" utility planning goals with the idea of "cost effective resource planning," which takes into consideration the costs and benefits of adding more renewable resources and DSM programs to the utility's resource plan for resource acquisition. This study is the first direct statewide assessment of new legislative mandates for more renewable and energy efficiency measures to reduce greenhouse gas emissions from Colorado's power sector.

1 INTRODUCTION

1.1 Global Greenhouse Gas initiatives

The Intergovernmental Panel on Climate Change's Second Assessment Report (IPCC, 1996) concluded that "the balance of evidence suggests that there is a discernible human influence on global climate" [1]. The IPCC, 1996 report formed the basis for the Kyoto Protocol, a global initiative on climate change developed by the United Nations Framework Convention on Climate Change (UNFCCC), which assigns its signatory nations mandatory goals for the reduction of greenhouse gas emissions. Signed in December 1997, the Kyoto Protocol went into effect on February 2005 [2].

The objective of Kyoto Protocol is the "stabilization of greenhouse gas concentrations in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time-frame sufficient to allow ecosystems to adapt naturally to climate change, to ensure that food production is not threatened and to enable economic development to proceed in a sustainable manner" [3]. Those countries that ratify the protocol commit to reduce their emissions of Carbon Dioxide (CO2) and five other greenhouse gases, or to engage in emissions trading if they maintain or increase emissions of greenhouse gases. The Kyoto Protocol now covers more than 160 countries globally and over 55% of global GHG emissions [4].

The Kyoto Protocol establishes key fundamental principles for the signatory countries to follow in the first commitment period (2008-2012):[1]

- Governments are separated into two general categories: *developed countries* (*Annex I countries*) who have accepted GHG emission reduction obligations, (with the exception of the United States and Australia) and who must submit an annual GHG inventory; and *developing countries (Non-Annex I countries),* who have no GHG emission reduction obligations but may participate in the Clean Development Mechanism.
- Any Annex I country that fails to meet its Kyoto obligation will have to submit 1.3 emission allowances in a second commitment period for every ton of GHG emissions they exceed their cap in the first commitment period.
- During the first period, Annex I countries are required to reduce their GHG emissions by an average of 5% below their 1990 levels. Reduction limitations expire in 2013.

[1] The second commitment period will be established in subsequent revisions.

Kyoto includes "flexible mechanisms," which allow Annex I economies to meet their GHG emission limitation by purchasing GHG emission reductions from elsewhere. These can be bought either from the main non-Kyoto compliant markets (such as UK Emissions Trading Scheme [ETS]; the European Union ETS; the Chicago Climate Exchange, or from projects that reduce emissions in non-Annex I economies under the Clean Development Mechanism or in other Annex-I countries under the Joint Implementation [5].

In a recent study by the World Bank, the need for future action to reduce the risks of climate change has played a major role on the international agenda. A variety of approaches are being implemented to reduce carbon emissions, ranging from efforts by individuals and firms to initiatives at the city, state, regional, and global levels. Major global initiatives to reduce nations' climate footprint include the 1992 UN Framework Convention on Climate Change and its 1997 Kyoto Protocol and Europe's carbon constraint for electricity generators and industry under the European Union ETS [5a].

Carbon markets now form a new sector in the worldwide economy. A credible response to climate change, these markets also provide a new and powerful tool for future climate mitigation. The World Bank's study valued carbon market growth at US$30 billion in 2006, three times greater than in the previous year. The study also showed that the market was dominated by the sale and re-sale, under the EU ETS, of European Union Allowances (EUAs) at a value of nearly $25 billion. Project-based activities through the CDM and JI also grew sharply, rising to a 2006 value of about US$5 billion. In 2006, the Chicago Climate Exchange and the New South Wales Market also traded record volumes and values.

1.2 Greenhouse Gas Initiatives in the United States

Currently the United States does not regulate CO2 domestically and the EPA has not promulgated emission limits for CO2. However, congressional attempts to mitigate carbon have begun to appear more frequently in legislative sessions (Table 1).

The U.S. is a signatory but has neither ratified nor withdrawn from the Kyoto Protocol.[2] On July 25, 1997, before the Kyoto Protocol was finalized, the U.S. Senate voted unanimously (S. Res. 98) that the United States should not be a signatory to any protocol that did not include binding targets and timetables for developing as well as industrialized nations and which "would result in serious harm to the economy of the United States." A successor to the Kyoto Protocol with a global cap-and-trade system that would apply to both industrialized nations and developing countries is in the works and could be in place by 2009 [6].

[2] The signature is symbolic. The Kyoto Protocol is non-binding on the United States unless ratified.

Table 1: Summary of Recent Air Emissions Legislative Initiatives

Legislative Initiatives	Sulfur Dioxide (SO_2)	Nitrogen Oxides (NOx)	Mercury (Hg)	Carbon Dioxide (CO_2)	Notes
Acid Rain Control Act of 2005 (109th Congress, H.R. 227) to reduce acid deposition under CAA	Nationwide 8.90 million tons reduced to 4.45 millions for 2010-2013 & 3.0 million tons thereafter	Nationwide- 2.10 million tons for 2010-2013 & 1.70 million tons thereafter	EPA Promulgate Hg reduction regulations for Eastern & western Regions for significant reductions	By 2009, EPA to identify credible indicators to protect ecosystems such as Rocky Mountains & others class I.	$6000/ton penalty for NOx non-compliance. Emission trading for Hg not allowed.
Clean Air Planning Act of 2005 (Introduced in House, H.R. 1873)	4.5 million tons for 2010-2013 & 3.5 million tons 2014-2016 and 2.25 million tons thereafter	1.87 million tons for 2009-2014 & 1.7 million tons thereafter	24 tons for 2010-2014 & shall not exceed 50% of Hg in Coal or 4lbs/TBtu and for 2015 & thereafter 10 tons and 30% of Hg in Coal or updated by EPA output-based rate.	Affected units' 2006 emission rates determined by EIA used for 2010-2014 and units' emission rates for 2001 used for 2015 & thereafter	Applies to >25 MW mercury and NOx allowance program. NOx allowance of 1.5lb/MWh of 3 years average & Hg allowance .0000227 lbs/MWh of 3 yrs avg. penalty NOx $5000, Hg $10000
Clean Power Act of 2005 (Introduced in Senate, S. 150)	By 2010 reduce national to 2.25, after 2010 western region to 2.75 & nonwestern region to 1.975 million tons	By 2010 reduce to 1.51 million tons	By 2010 reduce to 2050 million tons	By 2009 reduce to 5 tons	Cap-and-trade for all but Hg. Applies to >15 MW Allowances should be distinguishable between western & nonwestern region.
Clean Smokestacks Act of 2005 (Introduced in House, H.R. 1451)	75% reduction from the Phase II requirements under title IV	75% reduction from 1997 level	Reduction to 1990 level	90% reduction from 1999 levels	Cap-and-trade for all pollutants but Hg.
Clear Skies Act of 2005 (Introduced in Senate, S. 131)	30% by 2010 & 50% by 2018 from baseline or most stringent Federal or State emission limitation applicable to baseline year	30% by 2010 & 50% by 2018 from baseline or most stringent Federal or State emission limitation applicable to baseline year	By 2010, lesser of unit's baseline allowable emissions rate under NESHAP or most stringent Federal/State emission limitation applicable to baseline year	Not considered	Safety valve; allowances priced for SO_2 at $2000, NOx at $4000 and Hg at $2187.5 CPI adjusted. NOx zonal trades. WRAP specific SO_2 trades
Mercury Emission Act of 2005 (Introduced in Senate, S.730)	By 2010 & thereafter, 2.75 million tons in western region and 1.975 million tons in nonwestern region	By 2010 & thereafter, 1.510 million tons	For 2009, subject to section 112 of CAA not to exceed 2.48 grams per 1000 MWh & no coal type differentiated. And by 2010 thereafter, 5 tons nationwide limit.	By 2010 & thereafter, 2.050 million tons	

n the United States there is a voluntary program in place to collect and report information on annual greenhouse gas emissions. The Energy Policy Act (EPA) of 1992 directed the Energy Information Administration (EIA) to establish a mechanism for "the voluntary collection and reporting of information on annual reductions of greenhouse gas emissions [7].

The EIA, which has gathered and reported GHG emissions for the period of 1994-2004 [8], reports that in 2004:

- The U.S. power industry emitted 2,298.6 million metric tons of carbon dioxide (million $MTCO_2$) from the combustion of fossil fuels (coal, oil and natural gas) during the generation of electricity.

- Electric power generation accounts for 38% of total U.S. CO_2 emissions.
- Electric power generation accounts for 32% of total U.S. greenhouse gas emissions.

The report also indicates that, in 1990-2004:

- CO_2 emissions from the electric power industry have increased by 496.3 million metric tons, or 27 percent.
- This trend reflects rises in:
    - U.S. population, which increased by 18 percent, going from 248.7 to 293.7 million
    - Economic growth: GDP grew by about 51 percent
    - Corresponding increased electric power requirements.

Yet the report also indicates, for the 1990-2004 period, CO_2 emissions intensity from electricity generation fell by 2.1 percent, going from 0.593 MTCO2 per megawatt hour (MWh) generated in 1990 to 0.580 MTCO2 per MWh generated in 2004. The drop in CO_2 intensity reflects the increased use of natural gas and nuclear power for electricity generation [9].[3]

Although there is no mandatory requirement in the U.S. to reduce GHG, many states and local governments have begun with their initiatives and are moving ahead with their own legislation on GHG reduction programs. For example, Regional Greenhouse Gases Initiatives (RGGI) is a Northeastern states program to reduce GHG emissions, and California recently passed the Global Warming Solutions Act of 2006, A.B. 32 aimed at reducing carbon emissions from sources within the state. At the local level, many cities such as the City of Denver, are establishing Climate Action Plans for their own GHG reduction programs [11].

1.3 Regional Greenhouse Gas Initiatives (RGGI)

RGGI is a regional initiative by Northeastern states to reduce GHG emissions. Currently, the RGGI has eight participating states: Connecticut, Delaware, Maine, Maryland, New Hampshire, New Jersey, New York, and Vermont, and Massachusetts, Pennsylvania, Rhode Island, and the District of Columbia have shown interest in joining.[4]

Similar to the cap-and-trade program to control acid rain, the RGGI's cap-and-trade program seeks to reduce GHG emissions from electric power sector. It includes a carbon dioxide budget, state emission caps for fossil fuel-fired electric power plants of at least 25 MW of generating capacity, scheduled emission reductions, provisions for the use of offsets, and provisions for trading of carbon dioxide allowances.

[3] In 2005, EIA stopped producing the report on the Voluntary Reporting of Greenhouse Gases Program [10].

[4] Available online at: http://www.rggi.org/states.htm

Starting in January 2009, each participating State has agreed to cap its GHG emissions from power production with the goal of stabilizing emissions by 2015 to the level of three years' average emissions (2002-2004), followed by a 10% reduction between 2015 and 2020 [12]. The proposal allows participants to purchase offsets to meet 50% of their emission reductions.

RGGI energy modeling projects that, under RGGI policy scenarios, electricity prices will increase. Yet RGGI points out that: "policies to deliver meaningful end-use energy efficiency measures (both through RGGI and due to other state energy efficiency policies) are effective in sufficiently reducing total electricity usage by households so as to overcome the price increase impact of RGGI - resulting in a net reduction in expenditures on average across households. " The modeling methodology for RGGI GHG emissions reduction is discussed in Chapter 4 below.

1.4 California GHG initiatives

California's Global Warming Solutions Act of 2006 (A.B. 32) aims to reduce carbon emissions from sources within the state. The 2006 Act limits the state's 2020 carbon emissions to 1990 levels (roughly a 25% cut) and implements a reporting system to monitor compliance.[5] The Act specifies that all emissions from the generation of power consumed within the state are expected to be subject to the new laws. Because California imports power from neighboring states, emissions in those states may also be affected. In addition, through the West Coast Governors' Global Warming Initiative, California collaborates with Washington and Oregon on its greenhouse gas policy. The Act also includes an allowance trading program that has yet to be designed [13].

In 2006, the California Senate also passed a companion bill (S.B. 1368), which prevents load-serving entities from entering into long-term contracts for base-load generation unless the plants comply with a GHG performance standard. That standard will require that power imports from other states (currently about 25% of California power is imported) not exceed the rate of emissions for combined-cycle natural gas base-load generation. A "tax" would apply to power imports not meeting the standard [14].

1.4.1 West Coast Governors' Global Warming Initiative

The Governors of California, Oregon, and Washington have approved a series of recommendations for action to combat global warming and are working together on state and regional goals and strategies to combat global warming over the coming years. In November 2004, a staff report stated: [15]

> "...Global warming will have serious adverse consequences on the economy, health and environment of the West Coast states. These impacts will grow

[5] California has negligible coal-fired generation. Most of California generation is from Natural Gas, Nuclear, or Renewable.

significantly in coming years if we do nothing to reduce greenhouse gas pollution. Fortunately, addressing global warming carries substantial economic benefits. The West Coast region is rich in renewable energy resources and advanced energy-efficient technologies. We can capitalize on these strengths and invest in the clean energy resources of our region."

The Governors of three states have committed to act individually and regionally to develop strategies that promote long-term economic growth, protect public health and the environment, consider social equity, and expand public awareness in order to reduce greenhouse gas emissions below current levels.

1.5 Research Motivation

The motivation for this study derives from the fact that there is as yet no study of Colorado to identify the outlook for the state power sector's future CO2 emissions, to estimate costs and benefits, or to consider primary air pollutants in addition to CO2. Recently published reports have identified the state's growing need for electricity and plans on building more conventional, coal-fired power plants. Yet these plans of action fail to take into account the quantity and impact of CO2 emissions, despite the looming probability of future mandatory limits on CO2 emissions. See reports [19], [20], and [21]. This study is an attempt to provide a statewide energy planning and policy evaluation model that not only considers ways to respond to increased energy needs but also ways to decrease the sector's carbon and pollution footprint.

1.6 Research Objective

Through this research, we have developed a modeling framework and a Colorado-specific database to investigate scenarios of sustainable power generation. We used a MARKAL optimization model to:

- Model various scenarios for future sustainable energy production in Colorado
- Model ways to improve competitiveness of renewable energy
- Model ways to keep fossil fuel generation relatively competitive.
- Evaluate costs and benefits of alternative scenarios for statewide CO2 mitigation targets
- Evaluate reduction of criteria pollutants (SO2 and NOx) emissions as ancillary benefits.

In order to investigate scenarios of future electric generation technologies and their impact on state's future GHG and air pollutant emissions, the following scenarios were developed and evaluated:

- Reference Scenario (Business-As-Usual)
- Advanced Emerging Technology Scenario
- Energy Efficiency Scenarios
- Regulatory Policy Scenarios
- Sensitivity Scenarios

The research aimed to understand how technology and policy could affect Colorado's power sector CO_2 emissions intensity in the future. It also sought to develop an optimized assessment of power generation – existing and future – statewide to determine the best resource mix for sustainable energy in the future.

1.7 Research Impact

This study provides results of a Colorado-specific case study of the potential for efficient and clean energy technologies to address a number of energy-related challenges within the power sector facing the state. These challenges include climate change, recently promulgated Renewable Portfolio Standards, fuel price volatility, power transmission constraints, and inefficiencies in energy production.

Some of the challenges are visible today and are being integrated into public policies at various local governmental levels (see, for instance, the Greenprint Denver Council Climate Action Plan). Others are emerging and have uncertain future outcomes. How the state will respond to them will affect Colorado's economy and the well being of its citizens.

In considering the environmental impact of fossil-fueled electricity generation on the state's emissions levels, this study makes a major contribution to power sector planning. The study also explores clean energy technology and makes a strong case for the value of renewable energy in the state's energy program. Finally, the study identifies specific policy scenarios policymakers can use to design an appropriate environmental and economic response to Colorado's burgeoning energy needs.

2 BACKGROUND ON ENERGY OUTLOOK

2.1 The U.S. Energy Outlook

Recent volatility in energy prices has changed the future energy outlook. According to the Energy Information Administration (EIA)'s 2006 *Annual Energy Outlook (AEO2006)*, the cost of fuel delivered to electricity generators in 2025 will be higher than projected in the AEO2005. The projection of increased generation of electricity from coal-fired plants and decline in natural-gas fired generation is, in part, due to higher natural gas prices and slower growth in electricity demand compared to the 2005 projection. The *AEO 2006* projected electricity generation of 1,070 billion kilowatt-hours (kWh) from natural gas in 2025 is 24% lower than the year AEO2005 projection of 1,406 billion kWh [16].

2.1.1 The U.S. Carbon Dioxide Emissions

AEO2006 also projects carbon dioxide (CO2) emissions from energy use to increase from 5,900 million metric tons in 2004 to 7,587 million metric tons in 2025 and 8,114 million metric tons in 2030, for an average annual increase of 1.2% per year. Projected increased CO2 emissions from coal in 2030 is due to higher natural gas prices and the use of more coal generation to displace higher-cost gas generation. AEO2006 also projects 6 gigawatt (GW) of new nuclear capacity additions, with no additional new nuclear plants after 2020 due to expiration of the Energy Policy Act of 2005 (EPAct2005) production tax credit [17].

2.1.2 The U.S. Renewable Energy

U.S. expected capacity expansion from renewable generating units is projected to be about 8 percent. The U.S.'s renewable electricity generation is projected to grow by 1.7 percent per year to displace fossil-fueled electricity generation mainly due to higher fossil fuel prices. Growth is related to improved renewable technology and State Renewable Portfolio Standards (RPS). The expected affect of State RPS programs, which specify a minimum share of generation or sales from renewable sources, are included in this projection. The projection also includes the extension and expansion of the Federal tax credit for renewable generation through December 31, 2007, as enacted in EPAct2005 [17].

2.2 Colorado Energy Outlook

Recent uncertainty and volatility in natural gas prices has also affected Colorado's future energy outlook. In 2005, after nearly three-decades, a new coal-fired power plant with a capacity of 750 MW was approved to be built in Colorado with a service date of 2009 [18]. A recent report by Western Resource Advocates also reported that a new 600 MW coal-fired power plant is proposed to be built in the southeast of

Colorado [19]. A study by the Colorado Long Range Transmission Planning Group (CLRTPG) points out the possibility of building an additional 500 MW coal-fired unit in Brush, Colorado. The CLRTPG study is discussed in Chapter 5.

Climate Alert Report, published by Environmental Defense, raises concerns about the new trend for utilities to build ever more conventional coal-fired plants. The report emphasizes its concern by stating: "...In the southwestern United States, the race is on between efforts to curb global warming pollution and proposals to build more than a dozen outdated, high polluting power plants" [20]. The proposed increased generation of electricity from conventional coal-fired plants and decline in proposed natural-gas fired generation in Colorado is, in part, due to increased demand for base-load generation and to higher projected natural gas prices in future. This trend is consistent with the national trend projected by DOE/EIA.

In 2004, steam coal (43 percent) and natural gas (42 percent) fired power plants accounted for 85 percent of Colorado's installed power generation capacity. Of 42 percent gas generation capacity, 23% was combined-cycle generation capacity, and the remaining 19% combustion turbine generation capacity. Hydroelectric accounted for 6% and pumped storage facilities for 5%, whereas renewables (wind) and steam oil generating capability accounted for 2% each. (Figure 1)

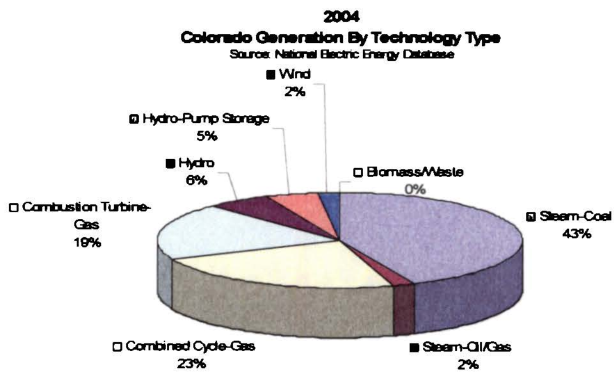

Figure 1: Colorado Electric Power Generation Capability in 2004

In 1990, 92% of Colorado's net power generation was from coal-fired generating power plants, and 4% from gas-fired generation. Due to the economic expansion of last decade, Colorado experienced a high growth in use of electricity that resulted in a surge of installed gas-fired generation capacity to meet the increased demand. In 2005, power generation from gas-fired units increased to 24% of Colorado net power generation, while generation from coal-fired met 72% of Colorado's net power

generation needs. Table 2 shows Colorado's net electricity generation by fuel type (percent share) in five year increments from 1990 to 2005.

Table 2: Colorado Net Generation by Fuel Type (1990-2005)

Fuel Type	1990 (MWh)	1995 (MWh)	2000 (MWh)	2005 (MWh)	Average Annual Growth Rate (%)	1990 Share (%)	1995 Share (%)	2000 Share (%)	2005 Share (%)
Coal	29,814,983	30,492,682	35,381,219	35,570,135	1.3%	91.6%	85.6%	80.1%	71.7%
Oil	27,390	11,712	109,385	17,046	-2.5%	0.1%	0.0%	0.2%	0.0%
Natural Gas	1,290,092	2,856,788	7,157,438	11,923,290	54.9%	4.0%	8.0%	16.2%	24.0%
Other Gas	0	0	0	2,430	-	0.0%	0.0%	0.0%	0.0%
Hydro	1,419,870	2,131,189	1,454,415	1,415,296	0.0%	4.4%	6.0%	3.3%	2.9%
Renewable	28,990	32,910	17,914	810,561	179.7%	0.1%	0.1%	0.0%	1.6%
Pump Storage	-33,198	91,953	45,175	-122,063	17.8%	-0.1%	0.3%	0.1%	-0.2%
Total Generation	32,548,127	35,617,234	44,165,546	49,616,695	3.5%	100.0%	100.0%	100.0%	100.0%

Source: DOE/EIA

Because coal prices are considerably lower than natural gas prices, coal-fired capacity is generally more economical to operate than natural-gas fired capacity. The Colorado share of natural gas generation was much less before the last decade, when a surge of new natural-gas fired plants were installed to meet needs and ensure reliability. These plants operate comparatively fewer hours than coal plants, coming into use only when electricity demand is high. (See Figure 2 for Colorado's net generation share by fuel type in 2005.)

A recent report by the Colorado Energy Forum (CEF) raised the question of what needs to be done today to ensure that all Colorado families, businesses, and communities have affordable, reliable, and environmentally sound sources of electricity in the decades ahead. The report concluded that, with Colorado energy demand expected to grow at approximately 2% per year until 2025, the state's utilities will need significantly more and newer transmission infrastructure to meet demand. [21]

There are over 60 electric distribution utilities serving end-users in Colorado. Aquila and Xcel energy (aka Public Service Company of Colorado) serve 59% of the state as regulated utilities under the jurisdiction of Colorado Public Utilities Commission. The other 41% of the state's end-users are served by non-regulated Municipal (18%) and Cooperative (23%) utilities [21]. Colorado's electric end-users consist of three main demographics: residential (34%), commercial (41%) and industrial (25%) (See Chapter 5 for details).

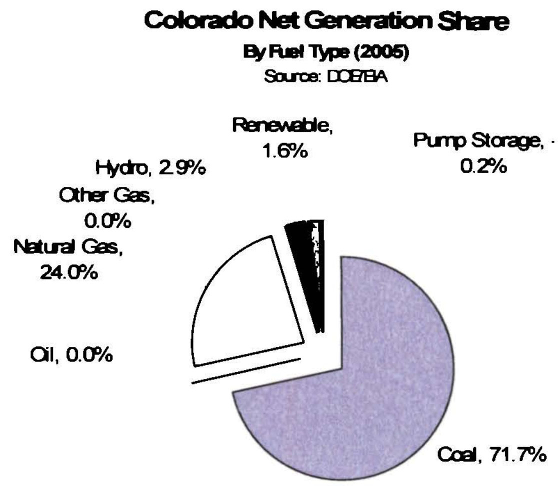

Figure 2: Colorado Net Generation in 2005

The CEF report projected Colorado's electricity need as 4,900-7,000 megawatts (MW) of new generation by 2025. To meet projected growth, the report suggests a generation portfolio mix of approximately 3,000 MW of base-load power, 1,500 MW of intermediate power and 1,350 MW of peaking power.

The CEF report, however, does not offer any recommendations on how the state should address its growing energy needs, nor does it offer any preferred future generation resource mix from the currently available choices – traditional electric generating resources, emerging advanced resources (integrated gasification combined cycle coal technologies, advanced combined cycle with carbon capture, and sequestration technology), renewable resources (wind, solar, geothermal), or energy efficiency. Rather, it outlines the magnitude of the problem and leaves it to the citizens of Colorado to determine the specific set of generation resources and energy efficiency measures required to address their growing need for power [21].

2.2.1 Colorado Sectoral Carbon Dioxide Emissions

In 1990, Colorado's total CO2 emissions from all sectors were 66.11 MMT, of which electric power's share was 30.96 MMT (47%) and transportation's was 18.90 MMT (29%). (Table 3)

Table 3: Colorado Historical CO2 Emissions (1990-2002)

Colorado CO_2 Emissions from Fossil Fuel Combustion Million Metric Tons CO_2 ($MMTCO_2$)													
Sector/Year													
Year	**1990**	**1991**	**1992**	**1993**	**1994**	**1995**	**1996**	**1997**	**1998**	**1999**	**2000**	**2001**	**2002**
Commercial	3.96	4.26	4.09	4.24	4.04	4.01	4.21	4.18	3.78	3.81	3.76	4.38	4.29
Industrial	7.00	7.91	8.13	8.84	8.34	8.20	8.45	8.80	9.25	9.03	9.60	12.96	12.33
Residential	5.29	5.76	5.51	6.09	5.68	6.10	6.45	6.27	5.94	6.39	6.82	7.26	7.49
Transportation	18.90	19.08	19.31	21.23	21.51	22.15	22.57	22.41	23.50	25.05	25.31	26.61	26.41
Electric Power	30.96	30.30	31.24	31.81	33.14	32.18	33.87	34.06	34.50	34.75	38.27	40.42	39.22
Total All Sectors	**66.11**	**67.31**	**68.27**	**72.22**	**72.71**	**72.64**	**75.54**	**75.72**	**76.96**	**79.03**	**83.77**	**91.62**	**89.74**

Source:http://epa.gov/climatechange/emissions/downloads/CO2FFC_2002.xls

See Figure 3 for CO2 emissions level distribution by five main sectors: residential, commercial, industrial, transportation, and electric utilities.

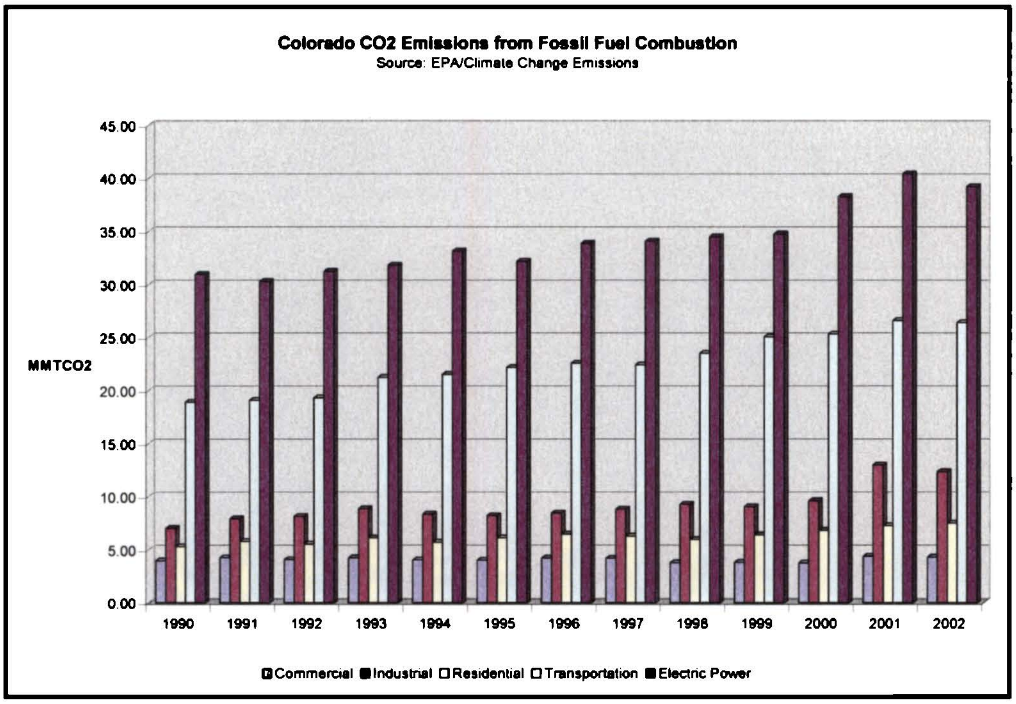

Figure 3: Colorado Fossil Fuel CO2 Emissions

Colorado Department of Public Health & Environment (CDPHE) Greenhouse Gas Emissions Inventory & Forecast (1990 through 2015) show Colorado CO2 emission for 1990 for all sectors at 78.72 million tons (71.56 MMT). The CO2 emissions from Colorado power sector for 1990 were 38.97 million tons (35.43 MMT). See Table 4.

Table 4: Colorado 1990 Carbon Dioxide Emissions by Sector

SECTOR	CARBON DIOXIDE (TONS)	PERCENT OF TOTAL
Utilities	38,966,038.07	49.6%
Transportation	19,430,412.68	24.7%
Industrial	9,826,549.78	12.5%
Residential	6,052,128.37	7.6%
Commercial	4,445,451.91	5.6%
Total	**78,720,580.81**	**100%**

CDPHE estimates show that, to generate electricity in 1990, Colorado utilities used 380.4 trillion Btu of coal and 5.1 trillion Btu of natural gas. (Table 5)

Table 5: Carbon Dioxide Emissions from Colorado Utilities Fossil Fuel Use (1990)

TYPE OF FUEL	FUEL CONSUMPTION (MILLION BTU)	CO2 EMISSIONS (TONS)
Biomass*	29,223.10	22.90
Bituminous Coal	380,424,360.00	38,666,331.95
Natural Gas	5,150,000.00	299,683.22
Total	**385,603,583.10**	**38,966,038.07**

Source: Colorado Greenhouse Gas Emissions Inventory & Forecast (1990 through 2015), Colorado Department of Public Health & Environment, Revised Oct. 2002.
*Biomass is no longer included in the greenhouse gas inventory per EPA's *State Workbook Volume VIII.*

CDPHE 2002 forecasts that by 2015, Colorado utilities will require 42% more coal and natural gas, with a corresponding rise in CO2 emissions . According to this scenario, power sector CO2 emissions measured at 38.9 million tons in 1990 will reach 55.4 million tons by 2015 (Table 6).

Table 6: Forecast of Carbon Dioxide Emissions from Colorado Utilities Fossil Fuel Use through 2015

FUEL	ENERGY CONSUMPTION (MILLION BTU)	CO2 EMISSIONS (TONS)
Bituminous Coal	540,659,105.21	54,952,591.45
Natural Gas	7,319,180.00	425,909.79
Other	41,531.16	32.55
Total Projected for 2015	**548,019,816.40**	**55,378,533.80**

Source: Colorado Greenhouse Gas Emissions Inventory & Forecast (1990 through 2015), Colorado Department of Public Health & Environment, Revised Oct. 2002.

From 1990 to 1997, Colorado CO2 emissions from utilities increased 7.58 %, rising from 38.97 million to 41.92 million tons. By 2005, utilities CO2 emissions were 45.17 million tons (41.06 MT), or 15.92% over 1990 levels.[6] Yet these figures do not take

[6] Source of CO2 emissions for 2005 is from EPA- Emissions Tracking System. Total CO2 tonnage does not include purchased power CO2 Emissions.

into account the fact that Colorado is a net importer of electricity. When CO2 emissions are added to for imported electricity, the utilities' CO2 footprint is even larger (Table 7).

In 2007, Colorodans alarmed by escalating CO2 emissions, passed a Renewable Energy Standard (RES) designed to bring CO2 emissions far below levels projected by CDPHE (See 2.2.3 below).

Table 7: Colorado Utilities Carbon Dioxide Emissions Compared to 1990 Level

Year	Coal Consumption (mm BTU)	Coal CO2 Emissions (tons)	Gas Consumption (mm BTU)	Gas CO2 Emissions (tons)	Total CO2 Emissions (tons)	% Increase form 1990
1990	380,424,360	38,666,332	5,150,000	299,683	38,966,015	-
1997	408,901,240	41,560,722	6,180,000	359,620	41,920,342	7.58
2005*	392,402,546	40,227,881	83,147,079	4,942,296	45,170,177	15.92

* U.S. EPA- Emissions Tracking System. Total CO2 tonnage does not include purchased power CO2 Emissions.

In this study, the *Reference Case* is benchmarked to 43.6 MMT CO2 emissions for 2005 including about 1.78 MMT CO2 for power imported into Colorado. In the *1990 Cap Carbon Policy Scenario*, CO2 emissions are capped at the 1990 level of 30.96 MMT.

2.2.2 Xcel Energy (PSCo) Carbon Dioxide (CO2) Intensity

Xcel Energy's Colorado operation is the Public Service Company (PSCo), which currently serves close to 60% of Colorado's electricity needs. In 2006, As part of the Greenprint Denver Council working group, Xcel calculated PSCo's CO2 intensity metric. According to thse calculations, in 2005 PSCo's owned generation CO2 intensity was 2,067 lbs/MWh. When combined with its purchased power 1,242 lbs/MWh, the company's CO2 intensity dropped to 1,748 lbs/MWh (Table 8).

Table 8: Xcel Energy (PSCo) CO2 Intensity

Xcel Energy (PSCo) Energy Resources Mix CO2 Intensity By Source Class and Energy Type (2005)						
	Generation Sources	CO2 Tons	MWh	CO2 %	MWh %	CO2 Rate (Lbs/MWh)
	Owned ETS Coal Units	20,933,481	17,557,807	65.6%	48.1%	2,385
1	Owned ETS Gas Units	1,971,936	4,324,392	6.2%	11.8%	912
	Owned non-ETS Coal Units	242,341	153,423	0.8%	0.4%	3,159
	Owned non-ETS Gas Units	3,215	3,009	0.0%	0.0%	2,137
	Owned non-ETS Hydro Units	0	197,468	0.0%	0.5%	0
2	Owned non-ETS Non-Emittor Units	0	160,472	0.0%	0.4%	0
	Owned Generation Subtotal	**23,150,973**	**22,396,571**	**72.5%**	**61.3%**	**2,067**
	Purchased Coal	3,175,342	3,028,211	9.9%	8.3%	2,097
	Purchased Gas	5,599,478	10,109,452	17.5%	27.7%	1,108
	Purchased Hydro	0	552,931	0.0%	1.5%	0
3	Purchased Zero Emittor	0	436,744	0.0%	1.2%	0
	Purchased Power Subtotal	**8,774,820**	**14,127,338**	**27.5%**	**38.7%**	**1,242**
	PSCo Energy Resources Total	**31,925,793**	**36,523,909**	**100.0%**	**100.0%**	**1,748**

Source: Chapman, D. *Xcel Energy's CO2e Intensity Metric*; Xcel Energy, 2006. Collected as part of the University of Colorado-Denver working group with the Denver Greenprint Council

As can be seen in Figure 4, coal fired power (owned) accounts for some 65.6% of PSCo's CO2 intensity, gas-fired power plants (owned) for 17.5%, coal generation (purchased) for 9.95%, and gas generation (purchased) for 6.18%.

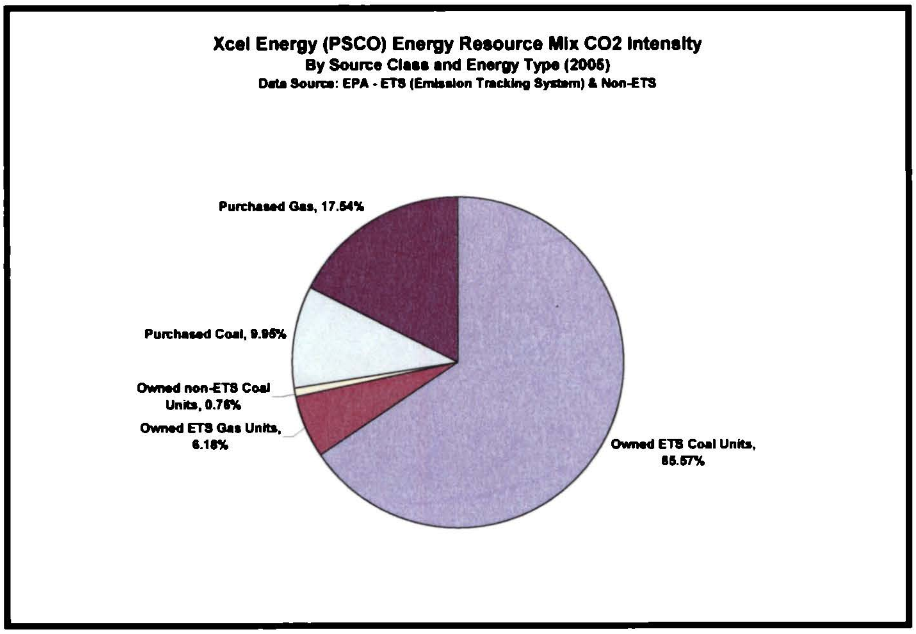

Figure 4: Xcel Energy (PSCo) Energy Resource Mix CO2 Intensity

2.2.3 The Colorado Renewable Energy Standard

In 2004 Coloradans passed "Amendment 37," a voter initiative that established the first Renewable Energy Standard (RES) in the nation. The 2004 RES applied to the state's two rate-regulated utilities: Xcel Energy (PSCo) and Aquila [22]. It allowed other Colorado covered utilities (serving 40,000+ customers) to opt out of the RES. It also allowed for exempt utilities, with a majority vote involving a minimum of 25 percent of the utility's customers, to opt in [23].

In 2007, Colorado revised and extended the 2004 RES requirements in House Bill 1281. This Bill increased requirements for the rate-regulated utilities in 2015 from 10 to 15%, and in 2020 and thereafter to 20%. The new legislation also requires cooperatives and municipally owned utilities to include renewable energy in their resource portfolio at the less stringent rate of 10% of retail sales by 2020. House Bill 1281 applies to every provider of retail electric service in the state of Colorado except municipally owned utilities that serves 40 thousand customers or less.

House Bill 1281 defines 'Renewable Energy Resources' as: solar, wind, geothermal, biomass, new hydroelectricity (with a nameplate rating of 10 megawatts or less), and hydroelectricity in existence on January 1, 2005 (with a nameplate rating of 30 megawatts or less). Fossil and nuclear fuels and their derivatives are not eligible energy resources. The Bill caps the retail rate impact of RPS in Colorado at 1%.

A number of other states have now instituted renewable fuel goals similar to those enacted in Colorado. In 2004, New York set its renewable energy production goal at 25% of by 2013. In 2005, Vermont set a voluntary goal of 10% of total electricity sales from renewable sources, a goal that will become mandatory if it is not met by 2012 [24].

2.3 Air Quality Impact of Electricity Generation

Electricity generation from current fossil fuel technologies produce a variety of atmospheric pollutants, including criteria pollutants (SO2 and NOx), particulates, CO2, and mercury. Table 9 (from EPA sources) shows the percentage of different pollutants produced by generating electricity, and how these variously affect ambient air quality, air toxicity, and climate change. Together SO2 and NOX contribute to acid rain, while SO2 also contributes to PM2.5 and NOX to ozone formation, further degrading ambient air quality. The fact that reducing GHG emissions can also reduce SO2 and NOx emissions, and thereby improve air quality, is an important policy consideration.

Table 9: Percent of Total Emissions from U.S. Electric Generation Technologies

Impact	Ambient Air Quality				Toxic	Climate Change	
	---------		Acid Rain				
Pollutant	PM10	PM2.5	SO2	NOx	Hg	CO2	N2O
Emission %	16	3	65	20	43	38	4

Source: EPA [28]

2.3.1 State's Electric Power Sector Air Emission Regulations

The U.S. EPA and several states have recently enacted air emission regulations governing the emission of NOx, SO2, and mercury from power plants. [7] North Carolina's Clean Smokestacks Initiative has announced compliance plans for the installation of SO2 scrubbers, selective catalytic reduction (SCR), and selective non-catalytic reduction (SNCR) NOx-removal technologies [16].

2.3.2 Colorado Electric Power Sector Air Emission Regulations

In 1998, Colorado's Senate Bill 98-142 authorized voluntary air pollution reduction from stationary sources owned by Xcel (PSCo) in metropolitan Denver [26], to be fully paid for by PSCo ratepayers.[8] The overall impact of this Metro Emissions Reduction act has been positive. SO2 emissions in metropolitan Denver have been reduced from historical highs by 62.7%, and SO2 emission are capped at 10,000 tons per year (Figure 5).

[7] The Clean Air Interstate Rule (CAIR) covers SO2 and NOx emissions in the Eastern U.S.; the Clean Air Mercury Rule (CAMR) covers mercury emissions nationwide; and the Clean Air Visibility Rule (CAVR) requires certain units - depending on their visibility impacts - to install pollution controls in certain areas of the country. EPA issued both CAIR and CAMR air emissions regulations in 2005.

[8] Xcel Energy is recovering the costs of implementing the Voluntary Emissions Reduction Agreement through a rate rider, Metro Emissions Reduction Air Quality Improvement Rider (AQIR), mechanism spread over a fifteen year period. Such mechanisms allow utilities to proactively seek improvements in operation of power plants in order to reduce emissions.

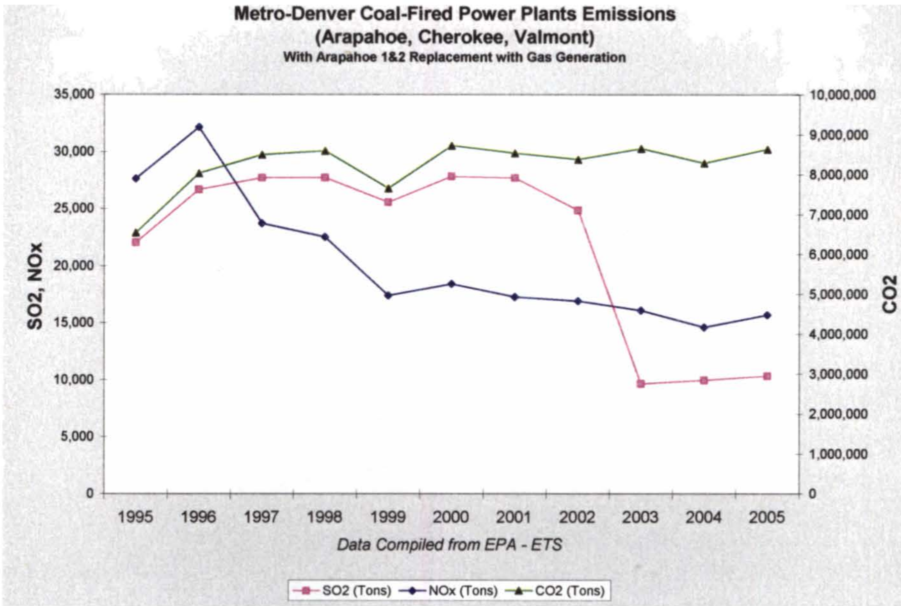

Figure 5: Metro Denver Voluntary Air Pollution Reduction Program
Source: EPA-ETS

NOx emissions, which were not capped, were voluntarily reduced by 11.8%. For the same period, however, CO2 emission increased slightly (0.3%) proportional to heat input increases (Table 10).

Table 10: Metro Denver Voluntary Air Pollution Reduction Program Results

Metro Denver Emissions And Heat Input	HEAT INPUT (mmBtu)	SO2 (Tons)	NOx (Tons)	CO2 (Tons)
Previous Three Years Avg. (2000-2002)	83,871,318	26,787	17,522	8,540,886
Three Years Avg.(2003-2005)	84,097,600	10,000	15,450	8,517,529
Percent Reduction (Increase)	(0.3%)	62.7%	11.8%	(0.3%)
Reductions (Increase)	(226,282)	16,788	2,071	(23,356)

Figure 6 shows SO2, NOx, and CO2 emissions from all coal- and gas-fired power plants in Colorado. As of 2005 in general, SO2 emissions had decreased, NOx emissions stayed almost the same, and CO2 emissions increased to above 45 million tons (41.06 MMT).

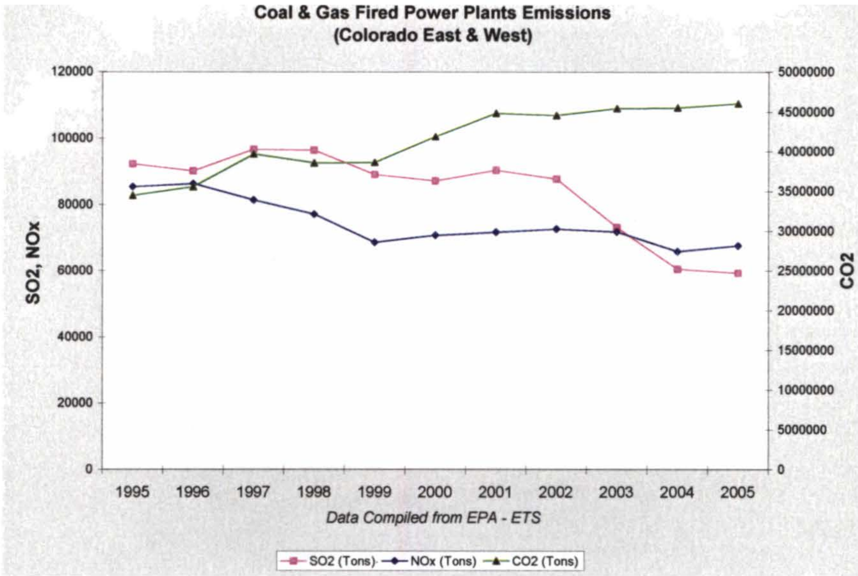

Figure 6: Colorado Power Plants Air Emissions
Source: EPA-ETS

Table 11 shows the cost of the Air Pollution Control (APC) component of the Metro Denver Voluntary Emissions Reductions Program. About 46% of this cost is attributable to retrofitting, 19% to fixed operation and maintenance (O&M) costs, and 16% to variable O&M costs. Recognizing the complexity of the problem, Coloradans have shown growing interest in strategies that address the problem of criteria pollutants, air toxins, and greenhouse gases simultaneously [36].

Table 11: Metro Denver Voluntary Emissions Reduction Program Cost Components

Metro Denver Voluntary Emissions Reduction Program Costs ('98$)	1998-2017 NPV ($1000)	% of Total
Emission Control Capital Revenue Requirements	94,898	46.4
Emission Control Fixed O&M Costs	38,967	19.0
Emission Control Variable O&M Costs	32,381	15.8
Emission Control Heat Rate Impacts (Fuel)	1,882	0.9
Arapahoe Replacement Capital Revenue Requirement	28,269	13.8
Arapahoe Replacement Fuel & Var. O&M Costs	6,129	3.0
Arapahoe Replacement Fixed O&M Costs	2,043	1.0
Total	$204,569	100.0

To ensure minimum funding for "cost-effective energy efficiency" programs, which would ultimately reduce greenhouse gas production statewide, the state could establish a similar ratepayer supported program. In 1996, California established a *public goods charge* (AB1890) that ensured minimum funding levels for "cost effective conservation and energy efficiency." By 2000, California's program had proved so effective that the state's extended it through the year 2011 and passed an additional natural gas surcharge (AB1002) for similar purposes. Also in 2000, California passed the Energy Security and Reliability Act (AB970), which directed the state's Public Utilities Commission to establish a distribution charge to provide revenues for a self-generation program. California also issued a directive to develop more energy-efficient and cost-effective electricity generation methods and to address the state's reliability concerns.[9]

In the spring of 2001, California set up a new state agency – the Consumer Power and Conservation Financing Authority ("CPA"). Created to encourage energy efficiency, conservation, and the use of renewable resources, the CPA was authorized to issue up to $5 billion in revenue bonds to finance energy efficiency programs and self generation activities.[10]

Colorado's regulators and policymakers already have some regulatory mechanisms in place to develop a framework for a continued energy efficiency funding. They can levy a Public Benefit Charge ("PBC"). A small carbon tax, based on consumption, could be collected from electricity users. These funds could then be used to generate additional funding to support more programs for energy efficiency and renewable energy, which would cut CO2 emissions in the long run..

[9] California Standard Practice Manual, Economic Analysis of Demand-Side Programs and Projects, October, 2001. Available online at: http://www.energy.ca.gov/.

[10] See 2004-2005 budget analysis, available online at: http://www.lao.ca.gov/analysis_2004/Resources/res_15_8665_anl04.htm

3 MODELING METHODOLOGY

3.1 MARKAL Model

This research utilizes the MARKAL modeling framework to investigate scenarios of future electric generation technologies and their impact on the environment. [11] MARKAL is a model that represents an energy system from the extraction or import of fuels, through their conversion to useful forms, to their use to meet end-users (i.e., residential, commercial, industrial, and transportation) demands. MARKAL (acronym for MARKet ALlocation) is a bottom-up, dynamic linear programming model.[12] The MARKAL model determines the least-cost pattern of technology investment while meeting the required energy demands and model constraints, and then calculates the resulting environmental impact such as greenhouse gas emissions [27a].

MARKAL model assumes perfectly competitive markets for energy carriers—producers maximize profits and consumers maximize their collective utility. The result is a supply-demand equilibrium that maximizes the net total surplus (i.e. the sum of producers' and consumers' surpluses). The model computes an inter-temporal partial equilibrium on energy markets, which means that the prices and quantities of various commodities are in equilibrium at all times, i.e., in each time period the suppliers produce exactly the quantities demanded by the consumers.[13]

The objective of the MARKAL model is to minimize the discounted total system cost for a region (or set of regions if multiple regions are modeled) obtained by adding the discounted periods' total annual cost. The total includes annual operating costs, annualized investment costs, and a cost representing the welfare loss incurred when demands for energy services are reduced due to their price elasticity. This objective is equivalent to maximizing the total surplus (consumers' plus producers' surpluses) [27b]. Figure 7 shows the price/demand trade-off curve where consumers' and producers' surpluses are maximized at an equilibrium quantity [37].

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[11] MARKAL model capabilities include; linear programming (LP) application focused strictly on the integrated assessment of energy systems, non-linear programming (NLP) formulation which combines the 'bottom-up' technology model with a 'top-down' simplified macro-economic model, stochastic programming to address future uncertainties, mixed integer programming techniques to model endogenous technology learning, and multiple regions modeling (NLP/LP). The MARKAL source code is written in the Generalized Algebraic Modeling System (GAMS) language. The model's documentation is available online at: http://www.ecn.nl/unit_bs/etsap/.

[12] Dynamic here means that all investment decisions are made in each period with full knowledge of future events.

[13] Partial equilibrium here means that the model computes both the flows of energy forms and materials as well as their *prices*, so that the suppliers of energy produce exactly the amounts the consumers are willing to buy.

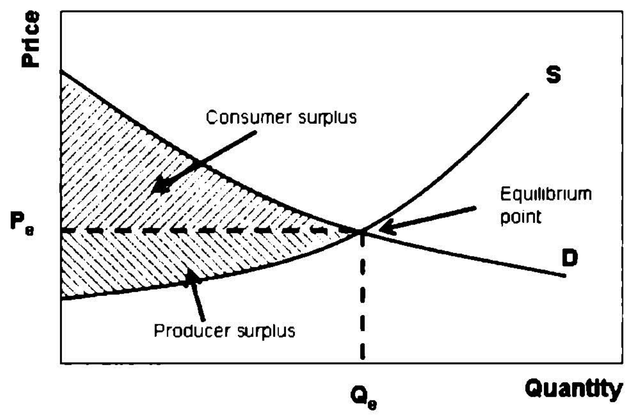

Figure 7: Price/Demand Trade-Off Curve

The building blocks depicted in Figure 8 represent MARKAL model stylized power sector network, referred to as a Reference Energy System (RES) consisting of energy carriers, conversion or resource technologies, and energy services.

The two basic components of an energy system model are commodities and processes. Commodities represent energy carriers (e.g., fuels, emissions, energy, etc.) flowing through an energy system. [14] A process transforms commodities from one form into another (e.g., power plants transform fuels into electricity). This user-defined network includes all energy carriers involved with primary supplies (e.g., mining or import of fuel), conversion and processing (e.g., power plants), and end-use demand for energy services. The demand for energy services may be disaggregated by sector (i.e., residential, commercial, industrial) and by specific functions within a sector [28].

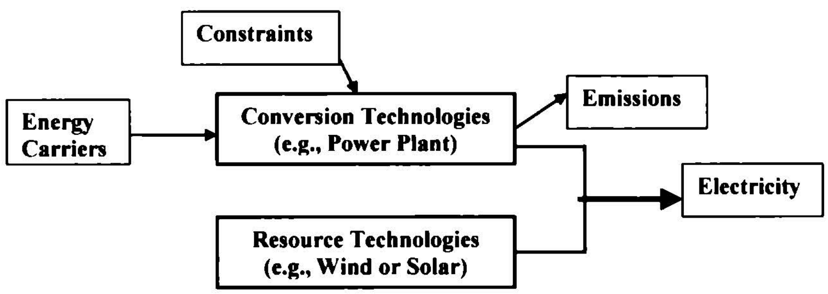

Figure 8: Generic Power Sector RES

[14] An *energy carrier (or energy source)* is anything in the energy system containing usable energy to produce another energy carrier (e.g. coal or gas used to produce electricity) or to produce usable heat or mechanical movement via certain technologies (e.g. gasoline, electricity, wood). An *energy service* is a commodity representing a demand for some useful service, such as heating of dwellings, etc.

3.2 MARKAL Model Applications

MARKAL energy and environment modeling framework has widely been accepted within the U.S. energy and environment modeling community. The U.S. EPA has developed a national MARKAL database and is working to regionalize the database into nine census regions [29]. In addition, the U.S. Department of Energy's Energy Information Administration (EIA) recently has adopted the MARKAL framework as the basis for its System for the Analysis of Global Energy Markets (SAGE) model. SAGE is used to produce EIA's annual International Energy Outlook. Altogether, MARKAL and its variants are used in approximately 40 countries around the world.

International research community has used MARKAL to develop strategies for addressing climate change and other environmental challenges. Gomez used MARKAL in surveying Technological Learning in Energy Optimization Models [30]. Makela used MARKAL to model the Nordic Electricity Production System [31]. And, Gielen used MARKAL to examine the integration of energy and materials systems engineering for GHG emissions mitigation [32].

MARKAL allows user to model energy, environmental, and policy issues, such as greenhouse gas emissions mitigation policies, to examine system-wide emissions limits on an annual basis or cumulatively over time. It also allows users to model the imposition of a carbon tax, or other fee structures. As a result, various costs for carbon may be generated for different levels of emission reductions. In this way, future technology configurations are generated and may be compared.

MARKAL is a demand-driven energy-economic model, which means that all the specified energy demands have to be satisfied. The user specifies the energy system structure, including resource supplies, energy conversion technologies, end-use energy demands, and the technologies needed to satisfy these demands. The user also defines technology fixed and variable costs, technical characteristics (e.g., conversion efficiencies), availability, performance attributes, and pollutant emissions. The specification of new technologies, which are less energy- or carbon intensive, allow the user to explore and evaluate the effects of these choices on total system costs, changes in fuel and technology mix, and the levels of greenhouse gases and other emissions [28].

3.3 EPA National MARKAL model

EPA's National MARKAL model is a comprehensive energy and economic model that simulates a national energy system by representing the interactions between resource supply (e.g., fuel), conversion processes (e.g., power plants), end-use technologies (e.g., heat pumps), and demand for energy services (e.g., space heating). The EPA's National MARKAL model represents the U.S. as one region.

EPA has adopted the MARKAL model to assess current and future energy technology options. EPA's national MARKAL model determines the least-cost pattern

of technology investment and utilization required to meet specified demands while satisfying model constraints (e.g., emissions caps), and calculates the resulting criteria pollutant and greenhouse gas emissions through 2030 [35].

3.4 EPA Regional MARKAL model

EPA has sponsored development of regional version of EPA's national MARKAL model. The regional modeling effort has provided an example of how the MARKAL model can provide useful analyses and tools to states and regions that need to make energy/technology decisions. The value of regional or state level MARKAL model as a valuable planning tool has been recognized by the EPA [33]:

> "...The U.S. EPA also recognizes the needs for integrated energy and environmental planning tools at the state and regional level. The advantage of a regional model is that it will accurately reflect the policy initiatives that are being designed and implemented by the states, using appropriate cost and performance characterization of the technologies that are available at the state and regional level."

Northeast States for Coordinated Air Use Management (NESCAUM) has developed and run the MARKAL model and technology database, NE-MARKAL. Each of RGGI New England states is modeled as its own region, with a focus on air quality and climate change.[15] Building on the lessons from NE-MARKAL, the U.S. EPA has been partnering with the bi-partisan Northeast-Midwest Institute and Ohio State University to build an Ohio-MARKAL model, with NESCAUM playing a supporting role to ensure compatibility.

EPA is also developing a nine-region MARKAL database (*EPA9R*), to address regional differences explicitly, that will account for variations in supply, demand, and technologies between the nine U.S. Census regions. EPA is expecting to use the *EPA9R* database to examine renewables in the future [29].

3.5 MARKAL Model Application to Colorado

Currently, there is no energy and environment model and technology database developed for Colorado. This study is the first power sector and environment modeling study, the Colorado Energy and Environment model, analyzing Colorado's power sector for a sustainable energy future.

Colorado is part of the14 states Western Electricity Coordinating Council[16], a region of the North American Electric Reliability Council (NERC)[17]. Most of the modeling

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[15] Available online at: http://www.nescaum.org/topics/ne-markal-model

[16] Western Electricity Coordinating Council, http://www.nerc.com/regional/wecc.html.

[17] NERC Regions, http://www.nerc.com/regional.

performed by various agencies includes Colorado with other western states. For example, DOE's Annual Energy Outlook modeling using NEMS[18] represents Colorado as part of the Rocky Mountain Power Area. EPA's Integrated System Analysis Workgroup (ISA-W) which contributes to the Air Quality Assessment is also developing a nine (9) region technology assessment and corresponding emission growth rates from the scenario analyses using MARKAL model which Colorado will be part of a broader region combined with other states [29].

Currently, there is no Colorado-Specific energy and environment technology assessment model that can assess Colorado's growing electricity needs and its corresponding emission growth rates. This study is the first to develop an energy and environment technology assessment modeling framework for Colorado.

[18] The U.S. Department of Energy, *National Energy Modeling System* (NEMS).

4 MODELING METHODOLOGY FOR COLORADO

4.1 Colorado Energy Model and Database Development

This study seeks to develop a working portfolio of resources and public policies to foster clean energy technology solutions to the energy and environmental challenges facing the state. These challenges include air pollution, greenhouse gas emissions, and inefficiencies in the production and use of energy. The purpose of the study is to estimate the costs and benefits of alternative sets of policies to accelerate clean and sustainable energy technology solutions in Colorado.

4.2 Energy Demand Forecast

Energy planning models require energy demand forecast for all the years in the planning horizon. There is no statewide long-term energy demand forecast available for Colorado that can be used for this study. Utilities in Colorado perform their own long-term forecast for their own use. The long-term forecast of the two regulated utilities (Xcel Energy and Aquila) that serve almost 60% of the state's load is publicly available. The other 40% of the state's load is served by cooperative and municipally owned utilities with limited publicly available long-term forecasts. Energy and Demand forecast is discussed in the next chapter.

4.3 Existing Generation Resources Data Sources

Based on EIA's 2005 *Annual Electric Generator Report* (EIA-860), there are 281 small and large electric power generators in Colorado.[19] The report shows that 18 of those generators are not connected to the electrical grid, 10 are retired, and 41 are in "Cold Standby" status. The National Electric Energy Data System ("NEEDS") database also contains the generation unit records used to construct the "model" plants that represent existing and planned/committed units in EPA modeling applications of Integrated Planning Model.[20] NEEDS includes basic geographic, operating, air emissions, and other data on generating units. The following data are available from NEEDS:

- Coal Supply and Transportation Assumptions
- Natural Gas Assumptions
- Federal and State Emission Regulations and Enforcement Actions
- Cost and Performance of Generating Technologies and Emission Controls
- Sulfur Dioxide (SO2), Nitrogen Oxide (NOx), and Heat Rates

[19] EIA-860, *Annual Electric Generator Report*, is available online at: http://www.eia.doe.gov/cneaf/electricity/page/eia860.html

[20] National Electric Energy Data System (NEEDS) is available online at: http://www.epa.gov/airmarkets/progsregs/epa-ipm/index.html#needs

- Power System Operating Characteristics and Structure
- Electric Generating Unit Inventory

NEEDS database generation unit records are utilized to construct the model's database for existing generating units in Colorado. Next chapter discusses in detail the existing and near future approved and planned generating resources.

4.4 Renewable Portfolio Standards (RPS) requirements

By 2020, about 16 percent of the expected retail sales of Colorado shall include electric power generation from renewable generating units.[21] This is based on retail sales of all qualified utilities within the state acquiring the maximum renewable energy under the Colorado RPS requirements. The amount of energy attributable to RPS requirements is estimated for both Investor Owned Utilities (IOU) and Non-IOU utilities for input to the MARKAL model. Table 12 shows total RPS renewable energy requirements for both IOU and Non-IOU utilities in Colorado.

Table 12: Colorado RPS Requirements

Year	Total RPS (GWh)	Effective RPS (% of Load)
2005	-	-
2008	1,864	3.40%
2011	4,268	7.20%
2014	4,589	7.20%
2017	7,774	11.40%
2020	11,624	16.00%
2023	12,338	16.00%
2026	13,051	16.00%
2029	13,765	16.00%
2032	14,478	16.00%
2035	15,192	16.00%

The cost and benefit of RPS coupled with its competitiveness with other least cost generation technologies to meet Colorado's energy requirements is quantified within the model. A Rule-Based scenario is designed to capture the RPS requirements within the model. The percent requirement is modeled as a floor (i.e., a lower bound since its mandated) for the renewable generation in Colorado. The Rule Based scenario also recognizes the fact that the RPS requirements for solar generation shall include 4% of RPS requirement from solar of which 2% shall be from distributed solar (i.e., rooftop solar). See section 5.8.1 for more discussion on RPS requirements.

[21] The 16 % is the weighted average of RPS requirement from Regulated and Non-Regulated utilities. It is assumed that regulated utilities will serve 60% of Colorado load with 20% RPS requirement and Non-regulated utilities serve 40% of Colorado load with 10% RPS requirement in 2020.

5 SCENARIO ANALYSIS

This section provides the results of scenario analysis by showing how technology evolution, energy efficiency and carbon policy could impact state's future power sector CO_2 intensity, and provides a statewide optimized assessment of power sector's existing and future generation resource mix for a sustainable energy future. This study establishes a database and utilizes MARKAL energy model to:

- Model alternative scenarios for sustainable energy future for Colorado's power sector while improving the competitiveness of renewable energy, and relatively keeping fossil fuel generation competitive.
- Evaluate costs and benefits of alternative scenarios for statewide CO_2 mitigation targets with criteria pollutants (SO_2 and NO_x) emissions reductions as ancillary benefits.

5.1 Approach

In order to investigate scenarios of future electric generation technologies and their impact on state's future GHG and air pollutant emissions, the following scenarios were developed:

- Reference Scenario (Business-as-Usual)
- Advanced Emerging Technology Scenario
- Energy Efficiency Scenarios
- Policy Scenarios, and
- Sensitivity Scenarios

The study concentrates on the electric power system of Colorado and presents the development of a supply-side energy system incorporating Renewable Portfolio Standards, Demand-Side Management and Energy Efficiency measures. The focus of the work is to demonstrate the current status of power sector in Colorado and quantify the pathways for sustainable future energy system.

The modeling horizon is 30 years. A year is divided into three seasons with spring and fall seasons combined. Seasons are divided into three time fractions; day, night, and peak hours. Since Colorado is a net importer, power imports from neighboring states are modeled to account for utility (take or pay) fixed contracts and other imports under pure economic conditions.

Within the main scenarios, total of 12 other scenarios, variant from the main scenarios, are modeled and analyzed, covering the time span from 2005 to 2035. The Reference Scenario (Business-As-Usual, "BAU") represents the most probable development of the power system under present known conditions while the other scenarios serve mainly for variation from BAU to show possible pathways for a

sustainable development of power system with main focus on clean energy technologies and mitigation of GHG emissions.

5.2 Reference Scenario

The development of energy scenarios allow a way to analysis and examine a range of resource portfolios and policies for consideration of alternative possibilities. An important step for any system planning modelling exercise is to establish a baseline scenario that represents a reasonable progression of the system's advancement into the future years taking into account certain aspects of the current and future conditions. Reference scenario serves as the basis for the subsequent analysis of alternate technology and policy scenarios. In preparation for this study, a Reference scenario has been established by:

- developing state-wide energy and demand forecast for each of three sectors (Residential, Commercial , and Industrial);
- adopting forecasts of energy supply prices from the DOE/EIA and the regulated utilities' filings before the state's Public Utilities Commission (PUC);
- establishing state's existing power plants installed capacity, coupled with Independent Power Producers (IPP) installed capacity;
- establishing state's mandated Renewable Portfolio Standards (RPS) requirements for all regulated and non-regulated utilities;
- establishing state's mandated Demand-Side Management (DSM) and Energy Efficiency (EE) requirements for all regulated utilities;
- establishing known near-term power plants retirements through state's PUC and utilities Resource Plans;
- establishing approved and proposed future power plants through state's PUC and utilities Resource Plans, and
- establishing assumptions for "guiding" model choices in situations where there are limitations on system evolution that inhibit the selection of ideal economic choices.

MARKAL is a least-cost optimization model for long-term energy system planning. Therefore, it is necessary to establish within the model the resources bounds and restrict some aspects of model choices to better reflect the conditions as the most likely evolution of state's electric power system, assuming a Business-as-Usual (BAU) perspective. BAU assumes a continuation of current energy policies using existing resources and adding planned and future conventional resources to meet electricity requirements of the state. Embedded within this assumption are limitations on how much the energy system will remain similar to what it is now, without intervention.

Representing each of these important aspects of the state's energy system in the model determines the nature of the Reference scenario. These are discussed in detail in the following sections.

5.3 Demand Forecast

Energy planning requires energy demand forecast for those years in the planning horizon. There is no statewide long-term energy demand forecast available for Colorado that can be used for this study. Utilities in Colorado perform their own long-term forecast for their own use. The long-term forecast of the two regulated utilities (Xcel Energy and Aquila) that serve almost 60% of the state's load is publicly available. The other 40% of the state's load is served by cooperative and municipally owned utilities with limited publicly available long-term forecasts. In order to develop a statewide energy and demand forecast for the planning horizon of 30 years, two recent studies were utilized; 1) the RMATS Study and 2) the CEF Report.

5.3.1 RMATS Study

In 2003, Governors of Wyoming and Utah announced the formation of the Rocky Mountain Area Transmission Study (RMATS) [25]. The sole purpose of RMATS was to conduct an analysis of generation and transmission alternatives within the region based on data, assumptions, and scenarios developed by the participating stakeholders. The RMATS region covers the States of Colorado, Idaho, Montana, Utah and Wyoming.

RMATS performed a Forecast of Energy and Demand for Colorado in September 2005. RMATS forecast combined total energy and demand requirements for Colorado East and West for the month of July (Summer Peak).

Table 13: RAMATS Colorado Energy and Demand Forecast

RMATS Forecast (September 2005)		
	2008	2013
Energy (GWh)	58,146	65,422
Peak (MW)	9,750	11,146

Table 13 shows RAMATS forecast for Colorado total energy requirements of 58,146 and 65,422 GWh for years 2008 and 2013, respectively. For the same years, RMATS forecast Colorado peak demand of 9,750 and 11,146 MW, respectively.

5.3.2 CEF Report

The Colorado Energy Forum also performed a study of Energy and Demand forecast for Colorado a year later in September 2006 [21]. CEF also projects the combined total energy and demand requirements for Colorado East and West. Table 14 shows the CEF forecast for total Colorado energy requirements of 52,656, 64,662, and 78,351 GWh for years 2006, 2015, and 2025, respectively. For the same years, CEF forecast a Colorado peak demand of 10,080, 12,400, 15,114 MW, respectively.

Table 14: CEF Colorado Energy and Demand Forecast

Colorado Energy Forum Forecast (September 2006)			
	2006	2015	2025
Energy (GWh)	52,656	64,662	78,351
Peak (MW)	10,080	12,400	15,114

A trend analysis was performed to curve fit historical data from DOE/EIA combined with the projected energy and demand data from RMATS and CEF.

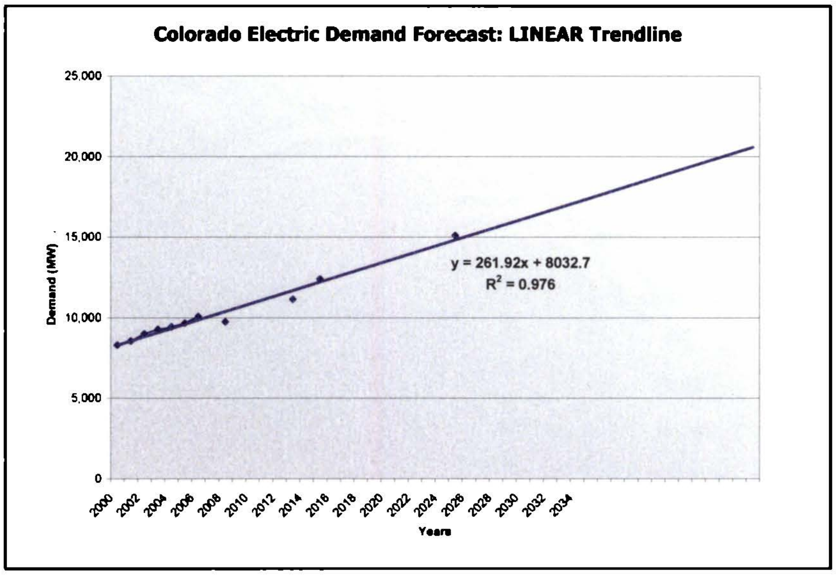

Figure 9: Colorado Peak Demand Trend (2005 -2035)

Figures 9 and 10 depict Colorado Peak Demand and Energy Forecast, respectively, using actual historical data for 2000-2005 combined with sparse projection data for 2008 and 2013 from RMATS, and sparse projection data for 2006, 2015, and 2025 from CEF.

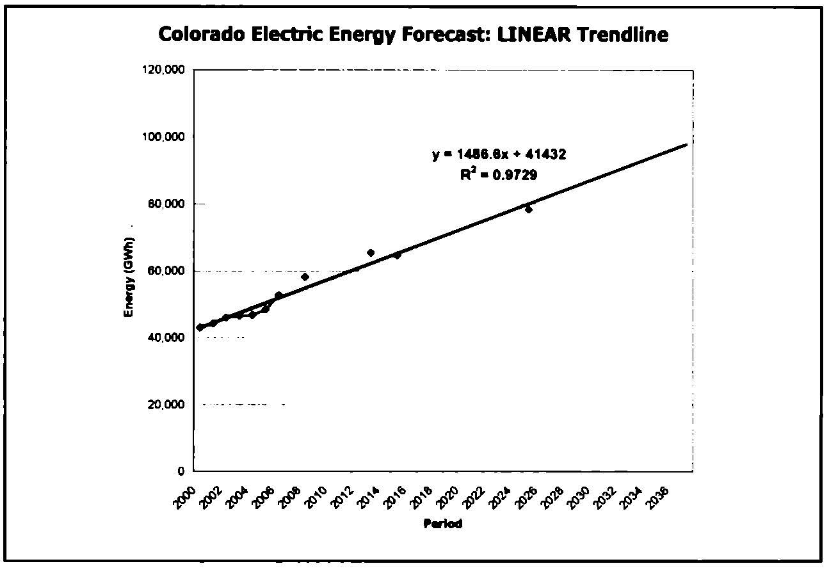

Figure 10: Colorado Energy Trend (2005-2035)

Results of Trend Analysis were used to build Colorado Demand and Energy requirements for each Sector. The End-Users in Colorado are represented by three sectors; Residential, Commercial, and Industrial sector. The relationship of each sector to total energy requirements were developed from available historical data from DOE/EIA for 2000-2005. Table 15 shows the distribution of total energy requirement among three sectors.

Table 15: Colorado End-Use Sectors Share of Total Energy Requirements

End-Use Percent Share of Total Energy Requirements		
Residential	**Commercial**	**Industrial**
34	41	25

The results of Trend Analysis show an average annual growth rate of 2.0% and 1.9% for energy and demand, respectively. See Tables 16 and 17 for Colorado energy and demand forecast, respectively, utilized in the model as Reference Scenario (BAU).

Table 16: Colorado Energy Forecast (Low, Base, High)

Colorado Energy Forecast (GWh)			
Year	Low (1.5%)	Base (2.0%)	High (2.9%)
2005	48,353	48,353	48,353
2008	53,138	54,811	55,270
2011	55,565	59,271	60,395
2014	58,103	63,731	65,995
2017	60,757	68,191	72,115
2020	63,533	72,651	78,802
2023	66,435	77,110	86,109
2026	69,469	81,570	94,094
2029	72,643	86,030	102,819
2032	75,961	90,490	112,353
2035	79,431	94,950	122,771

It is projected that Colorado will need to add - to the existing 2005 installed capacity of 11,232 MW - new generation resources of 3,361 MW and 7,196 MW for years 2014 and 2026, respectively.[22]

Table 17: Colorado Demand Forecast (Low, Base, High)

Colorado Demand Forecast (MW)			
Year	Low (1.5%)	Base (1.9%)	High (2.5%)
2005	9,664	9,664	9,664
2008	10,114	10,390	10,417
2011	10,575	11,176	11,218
2014	11,059	11,962	12,081
2017	11,564	12,747	13,010
2020	12,092	13,533	14,010
2023	12,644	14,319	15,088
2026	13,222	15,105	16,248
2029	13,826	15,890	17,497
2032	14,457	16,676	18,842
2035	15,118	17,462	20,291

A Low and a High projection are also estimated for the sensitivity analysis to alleviate the uncertainties with long term energy and demand projections. The Low energy projection results in an average annual growth rate of 1.5%, whereas a High projection provides an average annual growth rate of 2.9%.

[22] This need is based on the forecasted demand for each year plus a 22% reserve margin. For example, for 2014, the need of 3,361 MW is calculated by taking the forecasted demand of 11,962 MW plus 2,631 MW for reserve margin less 11,232 MW of existing installed capacity in 2005.This capacity estimate does not include any transmissions losses which usually run between 6-8%.

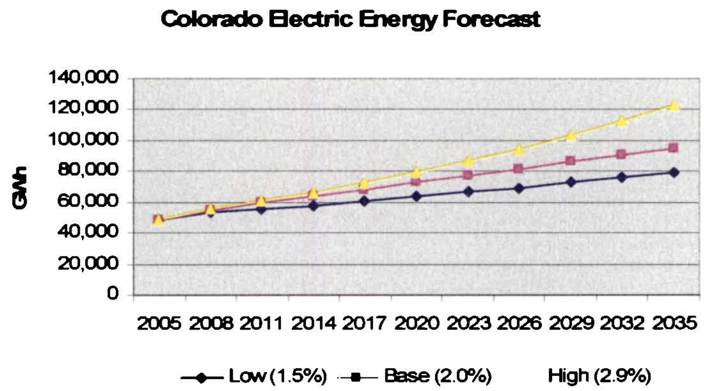

Figure 11: Colorado Energy Demand Projection (Low, Base & High)

Figures 11 and 12 depict Colorado Energy and Demand Forecast (Low, Base, and High) corresponding with Tables 16 and 17 above.

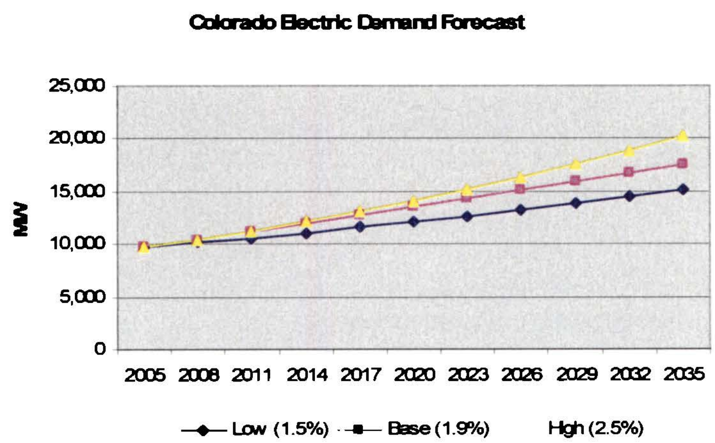

Figure 12: Colorado Demand Projection (Low, Base & High)

5.4 Demand Load Shape

MARKAL model for electricity uses six time-divisions. The year is divided into six time-divisions (time-slices), using two indices: Winter/Summer/Intermediate, and Day/Night. The demand for electricity in each season and time-of-day is calculated for all demand categories. This study disaggregates the time into finer divisions within the MARKAL model to represent the peaking technology more accurately. Other studies to date including the EPA's MARKAL model have dealt only with six time-slices [29].

Mountain region data from EIA was utilized to represent the sectoral demand load pattern for Colorado. EIA utilizes aggregated data corresponding to the categories end-users. There are four seasons of 3 months each: (1) December, January, February; (2) March, April, May; (3) June, July, August; and (4) September, October, November. There are 3 "time-of-day" categories: midday, morning/evening, and night. Thus, there are 12 categories to match to each sector.

There are three seasons: summer, winter, and the "shoulder" season which include spring and fall seasons. The "peak" hours is represented by using the top 1% of loads in each of the 12 categories thus 3 peak categories. Table 18 shows 12 time-slices load distribution for Colorado.

Table 18: Colorado Seasonal/TOD Sectoral Load Distribution

Season	Time-of-Day	Residential	Commercial	Industrial
Summer	Day	0.137	0.198	0.123
Summer	Morning/Evening	0.097	0.060	0.080
Summer	Night	0.026	0.019	0.046
Summer	Peak	0.004	0.004	0.003
Winter	Day	0.091	0.131	0.089
Winter	Morning/Evening	0.140	0.081	0.109
Winter	Night	0.031	0.016	0.045
Winter	Peak	0.003	0.003	0.003
Spring/Fall	Day	0.187	0.301	0.203
Spring/Fall	Morning/Evening	0.223	0.147	0.201
Spring/Fall	Night	0.050	0.031	0.092
Spring/Fall	Peak	0.006	0.008	0.006
Total		1.000	1.000	1.000

For the nine time-slice modeling, morning/evening category could be part of "day" and part of "night", thus it was split between day and night providing nine time-slices. Figure 13 shows Colorado nine time-slice load distribution patterns utilized in the model for Reference scenario.

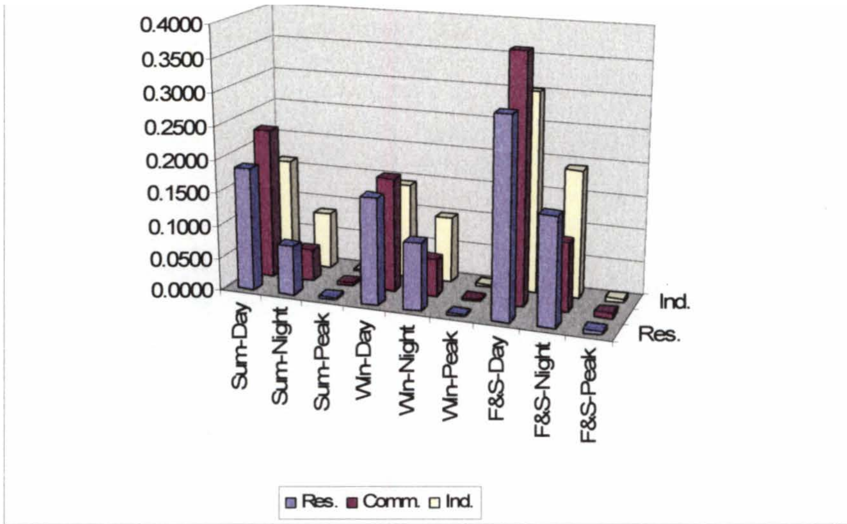

Figure 13: Colorado Nine Time-Slice Proxy Load Distribution

5.5 Supply Options Load Management

In MARKAL a conversion plants (e.g., coal-fired power plant) can produce electricity in each time division up to a level governed by the annual availability factor (AF) of that plant. For all existing and new power plants certain AF is determined based on available data and are utilized in the model.

Instead of a fixed and constant availability throughout the year, seasonal and time-of-day dependent values may be assumed by means of division-dependent to reflect resource availability for renewable power plants (e.g., hydro, solar, wind).

In this case, the production in each time division cannot exceed either of the levels given in the two conditions described above. The actual level of production for certain plants is then established as part of the solution of the MARKAL model, subject to these constraints and the demand load pattern.

In order to limit the load following characteristics of specific power plants, e.g. to avoid unrealistic operation patterns, so-called externally Load Managed plants can be modeled as well. Their production in each time division is fixed by means of annual time-sliced capacity factor (CF) parameters, but not both that is with AF.

5.6 Fuel Supply Prices

Fuel supply price input to the model are those developed by Xcel Energy for Colorado. Data for fuel supply prices were gathered from Energy Information Agency (EIA) and Xcel Energy's 2007 Colorado Resource Plan. Xcel Energy used various sources of data to compile and develop its fuel prices. For example, for gas prices, it

used a blend of New York Mercantile Exchange, EIA, and other sources. Figure 14 show the comparison of gas price projections by EIA and Xcel Energy. Natural gas price forecast developed by Xcel Energy is higher than EIA and more representative of fuel market in the west and therefore were adopted and utilized as input for Colorado model.

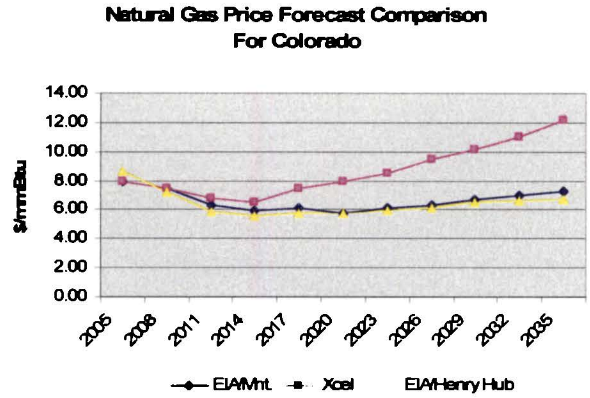

Figure 14: Natural Gas Prices Forecast

The same reasoning goes for other fuel types. For example, Xcel Energy developed coal prices for its Colorado operation using various sources as well. Both Powder River Basin (PRB) and Colorado-Wyoming (CO-WY) coal types are utilized in the model with prices adopted from Xcel Energy coal prices. Coal prices for both PRB and CO-WY coal resources are assumed to be the same. Figure 15 shows the comparison of coal price projections by EIA and Xcel Energy.

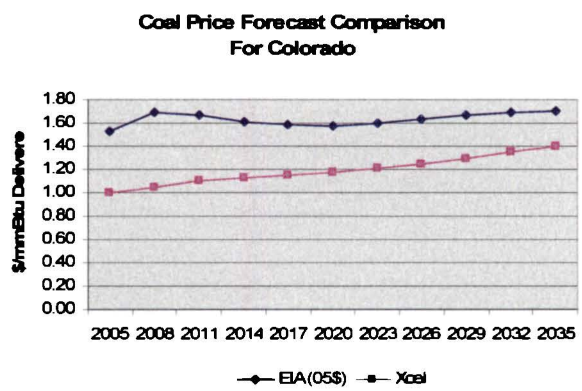

Figure 15: Coal Prices Forecast

Nuclear fuel prices were also adopted from Xcel Energy fuel prices. Figure 16 shows the comparison of nuclear fuel price projections by EIA and Xcel Energy.

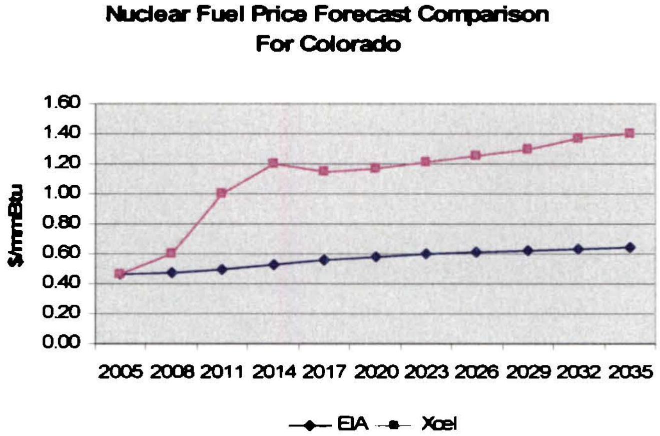

Figure 16: Nuclear Prices Forecast

Following are the sources of data for fuel prices:

- EIA price forecast from AEO2007
    - Report No. DOE/EIA-0383(2007), Gas Table 108, Coal Table 15, Full Report Release date: February 2007
- AEO2007, at 88, Nuclear fuel costs rise steadily to $0.62 per million Btu in 2030.
- Xcel Energy's 2007 Colorado Resource Plan, Price Forecast, Figure 1.7 of Volume 1.

5.7 Existing Installed Capacity

Table 19 shows the aggregated generating capacity in Colorado during the base-year 2005. The total installed capacity in Colorado was 11,232 MW which include 5,143 MW of Coal-Fired plants (1,733 MW of Bituminous coal, 3,410 MW of Sub-Bituminous coal). Colorado also has 4,226 MW of Gas-Fired power plants (1,760 MW of Combined Cycle and 2,460 MW of Combustion Turbine) and 107 MW Gas-Fired Steam plants, and 276 MW of Internal Combustion plants. The remaining includes 643 MW of Hydro, 563 MW of Pumped Storage, 265 MW of Wind, and 10 MW of Solid Waste. See Table 19.

Appendix A lists all the existing units utilized in the model as part of the Reference Scenario. Appendix B lists all generating units operating characteristics for year 2005 which include: number of hours each unit operated, energy input, power output, heat rate, and emissions factors. The emission factors shown in Table 19 are the

aggregation of emission factors from all units categorized by technology and fuel type.

Table 19: Colorado Existing Generation Mix & Emissions Rates (Input for 2005)

POWER PLANTS /PARAMETERS	CAPACITY (GW)	HEAT-RATE (BTU/KWH) (PJ/PJ)	SO2 (KT/PJ) OUTPUT	NOX (KT/PJ) OUTPUT	CO2 (KT/PJ) OUTPUT
Steam-Coal Bituminous	1.733	10,617 3.111	0.3008	0.4908	272
Steam-Coal Sub-Bituminous	3.410	10,473 3.069	0.4668	0.4088	270
Steam Natural Gas	0.107	13,387 3.923	0.0	0.3110	252
Combined Cycle Natural GAS	1.760	7,398 2.168	0.0	0.0193	111
Combustion Turbine Natural GAS	2.466	11,215 3.287	0.0	0.0716	175
Small IC NGAS/Oil	0.276	15,280 4.478	0.006	0.3110	252
Hydro	0.6429	-	-	-	-
Pumped-Storage	0.5625	-	-	-	-
Muni.-Solid Waste	0.0098	-	-	-	-
Wind	0.2647	-	-	-	-
Total Capacity	11.2319				

5.8 New Regulatory Landscape for Renewable and DSM/EE

Since 2004, Colorado voters and General Assembly have passed a number of Bills aimed at clean energy technologies and energy efficiencies with the goal of sustainable energy future and the reduction of greenhouse gas emissions from Colorado power sector. In 2004, Colorado voters passed Amendment 37 creating a Renewable Energy Standard ("RES") for the State which required 10% of regulated utilities retail energy to be produced from renewable energy resources. In 2006, Colorado Legislature passed new laws that encouraged the development of integrated gasification combined cycle ("IGCC") generation in Colorado. In 2007, new Bills doubled the amount of retail renewable energy to 20% for regulated utilities and added 10% requirement for non-regulated utilities (Cooperatives and Municipalities), encouraged the development of new transmission infrastructure to support the development of new renewable energy resources, and established energy efficiency and Demand-Side Management (DSM) goals for the regulated utilities (Investor Owned Utilities, "IOUs"). Also in 2007, The Governor of Colorado announced a statewide plan to reduce by 2020 carbon dioxide emissions by 20% from 2005 actual emission levels and to reduce CO2 emissions 80% by 2050.

These new legislative actions have created new challenges for both the regulators and the utilities. In its recent rule making, Colorado Public Utilities Commission (PUC) has recognized the significant impact of the new legislations on the utilities resource planning process and has eliminated the guiding principles of "least cost" planning and fuel neutrality with the concept of "cost effective" resource planning giving consideration of the costs and benefits of adding more renewable resources and DSM programs to the utility's resource plan for resource acquisition. This study is the first direct statewide assessment of new legislative mandates for more renewable and energy efficiency measures to reduce the state's greenhouse gas emissions.

5.8.1 Renewable Portfolio Standards

In 2004, Colorado's new Renewable Energy Standard (RES), the first in the nation, enacted through a voter initiative “Amendment 37”. The 2004 RES applied to two rate regulated utilities in the state, Xcel Energy (PSCo) and Aquila [22]. It allowed other Colorado covered utility (40,000 or more customers) to opt out of the RES, or an exempt utility to opt in, with a majority vote involving a minimum of 25 percent of the utility's customers [23].

In 2007, HB07-1281, increased the amount of electricity a utility must generate or cause to be generated from renewable energy resources (Renewable Energy Standard “RES” or Renewable Portfolio Standard “RPS”). The previous RES established by the voter-approved in 2004 Ballot Amendment 37, required utilities to meet a 10% RES by 201 5 and required 4% of that standard to be obtained from solar energy sources. HB07-1281 doubled these requirements by mandating that by 2020 qualifying regulated retail utilities (Investor-Owned Utilities “IOU”) meet a 20% RES. This legislation continued the requirement of Amendment 37 for the IOUs to satisfy 4% of the RES from solar resources. Also in 2007, another Bill was passed, SB07-100, which provided a mechanism for the designation of energy resource zones and the development of additional transmission infrastructure for delivery of from those zones energy (e.g., from small remote wind farms) to the load centers of the utilities. The Bill applies to each provider of retail electric service in the state of Colorado other than Municipally Owned utilities that serve forty thousand customers or less. See Table 20 for Colorado RES requirements.

Table 20: Colorado RES Requirements and conditions

YEAR ENACTED	REQUIREMENTS	ACCEPTS EXISTING CAPACITY	OUT OF STATE SUPPLY	CREDIT TRADING
2004	10% of rate regulated utilities retail electricity sales in Colorado shall include renewable energy by 2015; 4% of requirement must be solar of which 2% shall be distributed solar	Yes	Yes	Yes
2007	Rate regulated utilities retail electricity sales in Colorado shall include Renewable Energy or energy efficiency, or a combination of both as follows: 3% - 2007 5% - 2008 through 2010 10% - 2011 through 2014 15% - 2015 through 2019 20% - 2020 and thereafter Cooperatives and Municipally Owned utilities retail electricity sales shall include renewable energy as follows: 1% - 2008 through 2010 3% - 2011 through 2014 6% - 2015 through 2019 10% - 2020 and thereafter; 4% of renewable requirement must be solar of which 2% shall be rooftop solar	Yes	Yes	Yes

The eligible "Renewable Energy Resources" are defined in the Bill as solar, wind, geothermal, biomass, new hydroelectricity with a nameplate rating of ten megawatts or less, and hydroelectricity in existence on January 1, 2005, with a nameplate rating of thirty megawatts or less. Fossil and nuclear fuels and their derivatives are not eligible energy resources. The retail rate impact of RPS in Colorado is defined in the Bill to be caped at 1%. This study does not attempt to gauge the rate impact of RPS exogenously since it is assumed that the model is a least cost optimization model and internalizes the least cost resource options (conventional or renewable) within the model.

More States have instituted renewable goals similar to those of Colorado. In 2004, New York enacted a goal to have 25% of its generation from renewable by 2013. In 2005, Vermont enacted a goal that all growth, up to 10% of total electricity sales, shall be from renewable and the goal becomes mandatory if not met by 2012 [24].

5.8.2 DSM and Energy Efficiency (DSM/EE)

Energy efficiency is characterized as an alternative to energy supply options, such as conventional power plants that produce electricity by conversion technologies from fossil or nuclear fuels. Demand-side management resources act to reduce the demand for electric power and include a variety of measures such as energy efficiency, demand response, and energy conservation. There are two types of demand side resources: peak shavers and energy savers. Peak Shavers are used to reduce a customer's demand and energy requirements during peak hours. Energy savers are used to reduce energy over all periods of the year. An example of an energy saver would be replacement of incandescent light bulbs with more energy

efficient compact fluorescent (CFL) bulbs to reduce energy consumption throughout the year.

5.8.2.1 DSM Cost Effectiveness

In 1990s, the cost effectiveness of utility DSM programs was debated in various rate making proceedings. Historically, evaluation of energy efficiency and conservation programs are supported by engineering economics analyses where the present value of saved energy is estimated to exceed the initial DSM capital investment. However, more traditional economic analysis based on market failures, economic efficiency and the appropriate accounting of cost and benefits are also suggested for evaluation of energy conservation programs [38]. Several comprehensive studies using large databases of DSM technologies have published cost of DSM based on impact evaluation of DSM programs. In general, the studies have indicated the levelized cost of typical DSM programs cost utilities (Utility Cost) around $25-35 per megawatt hour saved on average, and have a TRC (Total Resource Cost) of $40-60 per megawatt hour saved on average [39].[23]

Generally speaking, DSM displaces gas-fired generation and sometimes coal generation as well. The major contribution of DSM/EE to any electric power system is the avoided cost of capacity and reduced fossil fuel consumption for generation, or the avoided purchased power cost.[24] DSM also has a major contribution to avoid the associated emissions of power generation such as C02 and criteria pollutants.

5.8.2.2 Screening of DSM Options: Cost Effectiveness Tests

In 1987, California developed standards for screening of DSM options which later was used by most jurisdictions including Colorado.[25] The practice manual defines five different benefit-cost tests: the Participant Test, the Ratepayers Impact Measure Test (RIM), the Total Resource Cost (TRC) Test, the Societal Test, and the Utility Cost (UC) Test.

The Participant Test measures the difference between the quantifiable costs incurred by a DSM participant and the subsequent benefits received by that participant. The RIM Test primarily measures the impact of DSM programs on the utility rates. The

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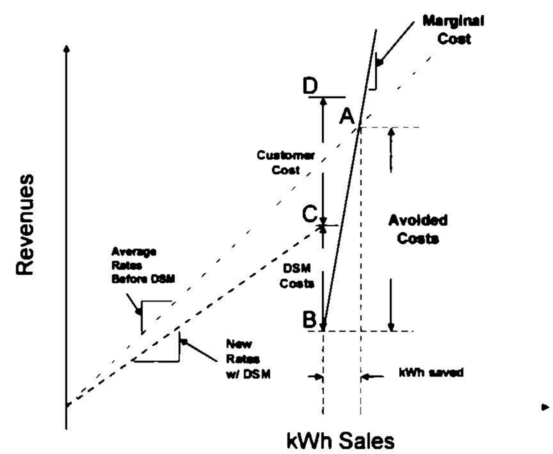
[23] Most of the large-scale studies were performed in early 1990s and the unit cost of DSM savings in terms of UC or TRC was in 1990s dollars. Most recent papers are still referring to these numbers as the cost of DSM programs. See M. Curtis 2004 paper on "Energy conservation in electric utilities: an opportunity for restorative economics at SaskPower," Technovation 24, at 399.

[24] DSM measures also contribute to savings in incremental transmission and distribution investment costs that utilities avoid in investing.

[25] The standards were developed by the California Energy Commission (CEC) and the California Public Utilities Commission in a process called the "California Collaborative Process" and published as the "Standard Practice Manual: Economic Analysis of Demand-Side Management Program." Available online at: www.energy.ca.gov/greenbuilding/documents/background/07-J_CPUC_STANDARD_PRACTICE_MANUAL.PDF

TRC Test (also called the All Ratepayers Test) compares the total costs of DSM programs (including costs incurred by the utility and the participant) and the avoided costs of energy supply. In a fact, the TRC Test is a summation of the Participant Test and the RIM Test. That is, benefits are still the total avoided supply costs, but costs are now the sum of the costs incurred by the customer and by the utility. The Societal Test includes the quantified effects of environmental costs (i.e., externalities costs) in the costs and benefits analysis of DSM programs. Finally, the Utility Cost Test measures the utility's avoided costs (i.e., costs related to fuel, operation and maintenance, and capacity costs) against the DSM program costs including rebates and administrative costs but not the customer costs.

Designing a DSM program that passes all standards tests is a difficult task. There are times that one test may pass the standards but others may fail. Figure 17 shows a case where the RIM Test is passed but the TRC Test is failed mainly due to the fact that the TRC is more than the benefits that is the avoided cost.



DSM example showing TRC Test fails (D above A), but RIM Test passes

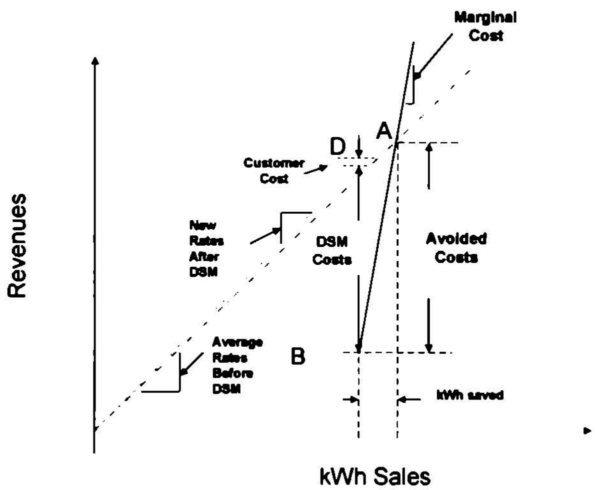
TRC=Total Resource Cost; RIM= Ratepayer Impact Measure

Figure 17: DSM RIM Test Example[26]

Figure 18 shows the opposite of the above case that is the TRC Test passes but the RIM Test fails mainly due to the fact that high DSM costs causes higher average rates for non-participants.

[26] Swisher, Joek N. and et al, 1997. *Improving Energy Efficiency and Protecting the Environment*, UNEP Collaborating Center on Energy and Environment, November.

It is most common to adopt TRC Test results because the benefits are still the total avoided supply costs, but the costs are the sum of the costs incurred by the utility and by the customers. This concept is adopted in this study to evaluate the cost effectiveness of state-wide aggregated DSM and Energy Efficiency measures taken by cities and local entities to redesign building codes and mandate energy efficiency programs within their jurisdictions to stay current with voluntary climate change initiatives.[27]



DSM example showing TRC Test passes (D below A), but RIM Test fails

TRC=Total Resource Cost, RIM= Ratepayer Impact Measure

Figure 18: DSM TRC Test Example

5.8.3 Regulated utilities DSM in Colorado

Colorado has two investor-owned utilities (IOU) subject to rate making regulations under the Colorado Public Utilities Commission (PUC). Both IOUs serve approximately 60% of the state's customers and provide about 59% of the electricity sales. The top 5 providers of Colorado's retail electricity in 2005 are shown in Table 21.

[27] See Denver Greenprint report available at: http://www.greenprintdenver.org/ and Colorado Climate Action Plan available at: http://www.colorado.gov/energy/in/uploaded_pdf/ColoradoClimateActionPlan_001.pdf

Table 21: Top Five Retail Electricity Providers in Colorado (2005)

Utility	Ownership	Sales (GWh)
Xcel Energy	IOU	26,481
City of Colorado Springs	Muni	4,479
Intermountain REA	Coop	1,929
Aquila	IOU	1,824
City of Fort Collins	Muni	1,393
Top Five Total Sales		36,106
Colorado Total Sales		**48,353**

Source: EIA State Electricity Profiles

Regulated utilities in Colorado, namely Xcel Energy and Aquila, have a major role to play in energy efficiency and conservation programs. Xcel Energy has been involved in DSM programs since 1980s through rate making regulations. As part of 2003 Least-Cost Planning (LCP), a Comprehensive Settlement Agreement was approved by the Colorado PUC requiring Xcel Energy to provide more DSM programs to its ratepayers with the approval of its proposed first coal-fired power plant in more than two decades.[28] Xcel Energy committed to undertake a total of 320 MW of demand reduction and 800 GWh of energy savings over the 8-year period (i.e., 100 GWh per year or 0.38% of annual sales) beginning in 2006 and ending in 2013. The total cost of this undertaking was proposed for approval at $196 million (1996 dollars).

In 2007, Colorado General Assembly passed the Energy Efficiency Bill, known as HB07-1037.[29] The Bill requires Colorado PUC to establish energy savings and demand reduction goals (e.g., sets minimum goals) for regulated utilities (IOUs) to acquire through energy efficiency conservation, load management and demand response programs. The impact of these goals is to reduce the energy and capacity that a utility would have traditionally planned to serve through supply-side resources. The Bill also allows for utility investments in cost-effective electric DSM programs to be more profitable to the utility than any other utility investment that is not already subject to special incentives. The legislation also specifies that the goal of DSM shall be consistent with allowing all classes of customers an opportunity to participate in DSM programs and be consistent by giving due consideration to the impact of DSM programs on non-participants and on low income customers which basically means no rate increases due to increased DSM measures.

5.8.4 Impact of New Legislation on DSM in Colorado

In 2007, Xcel Energy offered an Enhanced DSM Plan to its customers. For the period 2009-2020, in addition to 2003 LCP Agreement, Xcel Energy will spend $738

[28] See Xcel Energy's Certificate of Public Convenience and Necessity for Comanche 3 Pulverized Coal Power Plant before the CPUC, Dockets 04A-214E, 04A-215E, and 04A-216E.

[29] House Bill 07-1037, "*CONCERNING MEASURES TO PROMOTE ENERGY EFFICIENCY, AND MAKING AN APPROPRIATION THEREFOR*", enacted 2007.

million (2006 dollars) on more DSM programs to achieve 2,350 GWh (i.e., about 200 GWh per year) of energy savings. Table 22 shows Xcel Energy's Annual Incremental DSM Programs Energy Savings in addition to programs in place in 2006.

The annual incremental energy savings will peak at 1,284 GWh or 3.6% of total retail sales in year 2021 and will start decreasing thereafter unless more DSM programs are added.[30]

Table 22: Xcel Energy Cumulative DSM Programs Energy Saving in Colorado

Years	Programs In Current Plan	HB 07-1037 Programs (as of May 07)	Total Energy Savings (GWh)
2007	99		99
2008	202		202
2009	313		313
2010	430		430
2011	552		552
2012	670		670
2013	779		779
2014	767	101	868
2015	752	197	949
2016	735	292	1027
2017	718	384	1102
2018	700	472	1172
2019	683	543	1226
2020	670	600	1270
2021	670	614	1284
2022	670	569	1239
2023	657	527	1184
2024	621	483	1104
2025	613	407	1020
2026	605	322	927

Source: Xcel Energy, June 2007

The cumulative annual energy savings in Table 22 are modeled in Reference Scenario representing BAU. For example, for year 2020, total energy savings of 1,270 GWh is modeled as DSM contribution to energy savings at the penetration rate of 25% Residential and 75% Commercial. Xcel energy performed a comprehensive DSM study suggesting the DSM penetration distribution rate in Colorado is 25/75 between residential and commercial customers, respectively [40].

Figure 19 shows the cumulative energy savings within the Xcel Energy's system from current and proposed DSM action plans. The total energy savings peaks at 1,284 GWh in year 2021 and begins to decrease thereafter unless more DSM investments are made.

[30] The amount of cumulative peak energy savings of 1,284 GWh in year 2021 translates into 3.6% of Xcel Energy's forecasted retail energy requirement of 35,834 GWh in 2021. See Xcel Energy's 2007 Colorado Resource Plan, Vol. 2 Technical Appendix, at 2-129.

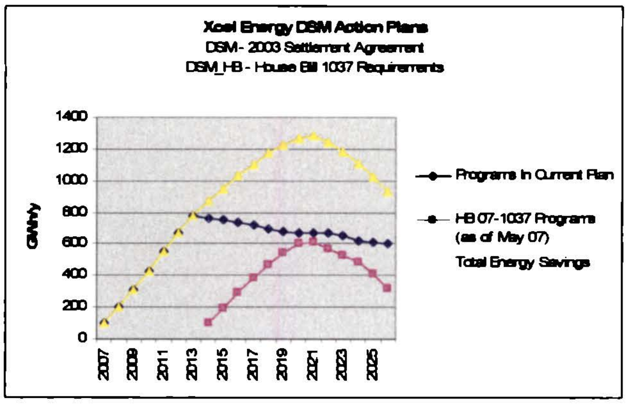


Figure 19: Xcel Energy DSM Programs

In this study, DSM is modeled as a resource contributing to the reduction of total energy requirements and the system's need for fuel and new capacity over the life of the DSM resource. Xcel Energy's maximum hour avoided marginal energy prices from recent DSM docket are adopted as the utility avoided costs for the cost of DSM programs since Xcel Energy is the largest utility actively pursuing DSM measures in Colorado. Figure 20 shows Xcel Energy (aka, Public Service Company of Colorado) Avoided Marginal Energy Prices utilized in its 2007 DSM Docket.

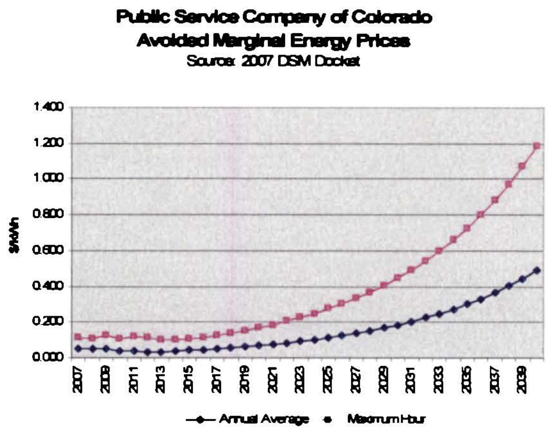


Figure 20: Xcel Energy DSM Avoided Marginal Energy Prices

Beginning in 2010, Xcel Energy has started to estimate the annual avoided emission costs as environmental benefits of DSM measure. Figure 21 shows Xcel Energy's estimated annual avoided emissions costs. In this study, Reference Scenario internalizes the DSM avoided emissions as part of energy efficiency/conservation

benefits by using less fossil fuel generation mostly gas generation and the associated CO_2 and NOx emissions related to gas fired generation technologies.

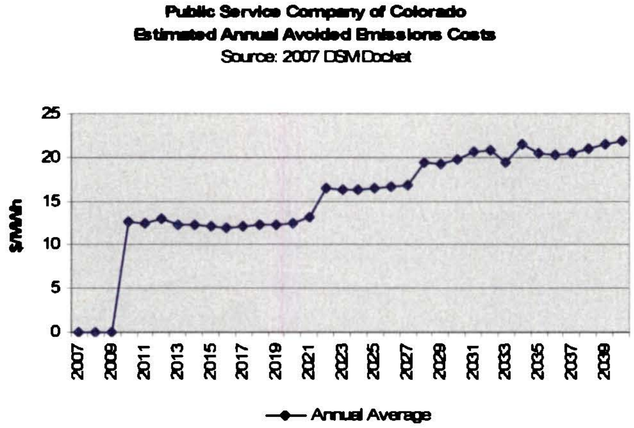


Figure 21: Xcel Energy DSM Avoided Emissions Costs

5.9 Integrated Gasification Combined Cycle (IGCC)

IGCC is a power generation process that integrates a gasification system with a conventional combustion turbine combined cycle power block. The IGCC advanced technology is commercially available for generating electricity with coal with the promise of substantially reducing air emissions, water consumption, and solid waste production from coal power plants. The gasification system converts coal into a gaseous "syngas" which made of hydrogen and carbon monoxide. The combustible syngas is used to fuel a combustion turbine to generate electricity, and the exhaust heat from the combustion turbine is used to produce steam for steam turbine cycle and the gasification process [41].

The IGCC technology is in its infancy with a relatively high cost option. The first large-scale IGCC plant of 629 MW was proposed by American Electric Power to be operational in New Haven, West Virginia at a cost of $2.23 billion (I.e., $3,545/kW) and recently was approved by West Virginia PUC.[31] In addition to being affected by the current increases in construction labor and material costs, an IGCC project also must absorb the costs of CO_2 capture and sequestration as well as costs involved in first generation design.

According to Electric Power Research Institute (EPRI) Technical Assessment Guide, the cost estimates made early in the development period of a new technology are low by a factor of two or more (expressed in constant dollars) compared with the

[31] Source: e-newsletter from POWER magazine, June 2007 and March 2008.

actual costs of the first commercial version of the technology. EPRI's TAG refers to this effect as the learning curve phenomenon which affects the costs to decline after a new technology is commercialized and improved versions of the new technology are built [42].

In 2006, Colorado Legislature passed a new law (HB06-1281) that encouraged the development of integrated gasification combined cycle ("IGCC") generation in Colorado. The Bill directed Colorado PUC to consider proposals by electric utilities to fund, and construct an "IGCC" project with CO2 capture and sequestration (CCS). Colorado PUC has defined "Section 123 resources" within its Resource Planning Rules as meaning "new energy technology or demonstration projects including new clean energy or energy efficient technologies and IGCC projects." [32] This legislation encouraged electric utilities to investigate the development of IGCC projects. Xcel Energy in its 2007 Colorado Resource Plan has proposed one 600 MW IGCC plant with 50% CCS to be constructed in Colorado by 2016. Reference Scenario (BAU) captures this IGGC plant with the start date of 2017. Plant's characteristics including investment and O&M costs are adopted from Xcel Energy's 2007 Resource Plan.

A number of coal-related provisions such as a loan guarantee for an IGCC plants were authorized by EPAct2005. These provisions have spurred some activity and interest by the utilities. Xcel Energy - has proposed building a 600 MW IGCC facility in Colorado (owning 150 MW) as the Western IGCC Demonstration Project.[33] The Xcel Energy's proposed IGGC project is captured in this study by modeling a 600MW IGCC unit with an in-service date of 2017 both in the BAU scenario and BAU plus Advanced Technology scenario.

5.10 Renewable Technologies

Renewable electricity generation encompasses a collection of technologies including:

- Biomass-fired generators
- Landfill methane
- Solar generators;
    - Photovoltaics technology (rooftop PV and central PV)
    - Solar thermal storage
- Geothermal power
- Wind turbines

[32] Section 123 refers to Colorado Revised Statutes. See C.R.S. for energy efficient technologies under section 40-2-123(1) and IGCC projects under section 40-2-123(2).

[33] *AEO2007*, suggests recent discussions among the industry experts indicate that 300-350 MW IGCC may not be economically feasible. The size of Xcel's IGCC was first suggested at 300 MW range but in its 2007 Resource Plan a 600MW IGGC plant is considered.

Just a few years back, generating electricity from renewable energy sources were considered more costly than from conventional sources, in particular natural gas generation. Recent advances in renewable technologies coupled with incentives and tax credits from federal government and high cost of natural gas have made renewable sources increasingly competitive with conventional sources.

Each of above technologies has found market opportunities especially when supported by government policies and incentives. Absence government incentives, a few are able to compete directly with available best conventional generation technologies. The push towards more renewable generation over the next decade will significantly change the cost and availability of renewable technologies, as increased demand induces more research and development that will bring many improvements in renewable technologies resulting in lower costs and better performance. As discussed in IGCC section above, the learning curve phenomenon will cause the costs to decline as the industry matures and improved versions of the new technologies are built.

5.10.1 Biomass

Biomass is plant matter such as trees, grasses, agricultural crops or other biological material. It can be used as a solid fuel, or converted into liquid or gaseous forms, for the production of electric power, or heat.[34] Biomass facilities for electricity generation are often considered base-load plants with capacity factors of 85% or better.

Electricity generation from biomass resources already accounts for a significant amount of total renewable electricity generation. There are three types of biomass generation:

- Co-firing of biomass in combination with coal in existing coal-fired power plants
- Direct firing of biomass in dedicated systems, and
- Gasification of biomass for combustion in gas turbines

Currently, biomass fuel sources are typically converted to electricity through combustion in an internal combustion engine or a steam boiler. Although most combustion units are direct-fired, research is under way to more fully develop biomass gasification processes: the ultimate product of these two processes is a biogas that can be combusted.

Co-firing biomass with coal is currently used in handful of power plants around the country. Colorado Springs Utilities (CSU) recently conducted a study to burn biomass with its coal-fired units. The study confirm the benefits of biomass co-firing by stating "Co-firing with biomass fuels will generally result in lower SO2, NOx, CO2, mercury and other emissions than firing with 100 percent coal. Percent reductions in

[34] See NREL Biomass research link at: http://www.nrel.gov/biomass/

emissions are generally proportional to the co-firing percentage (heat input basis). Reductions in NOx have been more difficult to predict accurately." The study conducts interviews with plant operators and confirms that biomass co-firing has minimal impact on the system operation by stating "...few impacts on system operation (in either a negative or positive manner) during co-firing tests conducted over three months at the Ottumwa facility. The only significant impact was a reduction in the percentage of SO2 emissions during co-firing equivalent to the reduction in percentage of coal fed to the boiler." [43]

Studies show that co-firing 5-15 percent biomass mixture with coal requires only minor burner and feed intake modifications to existing units with minimum capital costs of less than $50/kW to achieve a co-firing at a level of 10 percent. Co-firing entails no loss of efficiency and can contribute to the reduction of CO2 and criteria pollutants emissions. CO2 emissions from the combustion of biomass is generally considered CO2 neutral; however, increasing attention is being paid to the neutrality of CO2 emissions from forest products given the long time periods for conversion of atmospheric CO2 to plant material.

Any marginal increases in operating costs associated with the biomass resources are offset by the value of the emissions reductions benefits from co-firing biomass. National Renewable Energy Laboratory's 2003 biopower technical assessment concludes that the marginal O&M costs for biomass co-firing, exclusive of feedstock costs, are 0.23 cents per kWh less than those burning coal [44].

In this study, biomass is modeled as stand alone biomass gasification combined cycle and also with co-firing option with all bituminous coal fired units in Colorado at the ratio of 10 percent biomass and 90 percent coal. The competitiveness of biomass generation technologies heavily depends on the price and availability of biomass fuel resources. For biomass generation to become a major player in the RPS, the prices for biomass feedstock will need to be competitive with coal prices at near or under $2.00 per million Btu (mmBtu). Biomass supply curve developed by the U.S. Department of Energy (DOE) estimates that biomass fuel resources are available at prices around $2.00-2.50/mmBtu.[35] In this study, the DOE average price of $2.25/mmBTu escalated at an inflation rate of 1.5% over the planning horizon is adopted. It is also assumed that the reductions in marginal O&M costs as reported by DOE offsets any capital improvement or retrofit costs for co-firing which is reported to be less than $50/kW.

5.10.2 Geothermal

Geothermal resources convert extremely hot underground geothermal water into electricity and are generally run as base-load facilities. Three basic technologies exist to extract heat from underground reservoirs for the production of electricity:

[35] U.S. DOE Biomass Program publications: Available online at: www1.eere.energy.gov/biomass/

direct steam, flash steam, and binary cycle; each technology is best suited to the type of reservoir available. Based on surveys conducted to date, Colorado's relatively low-temperature geothermal resources are expected to be best utilized with binary cycle technology. Given the nature of the fuel source and the reliability of the power block, geothermal-generated electricity is considered a base-load resource with capacity factors between 85-95%. Relatively low levels of $C02$ and $SO2$ are emitted from direct steam and flash steam facilities [45]. Geothermal technologies are modeled as base-load power plants.

5.10.3 Solar

Recent report by the Western Governors' Association (WGA) projects as much as 8,000 MW of solar capacity could be installed in the Western states with a combination of distributed solar electricity systems and central concentrating solar power (CSP) plants by 2015, and an additional 2,000 MW of solar thermal systems could be installed in the same timeframe. WGA further projects by 2015, the cost of electricity from future CSP plants should be competitive with plants burning costly natural gas, and distributed systems should have declined in price to the point that they should be able to produce electricity below retail utility rates in most parts of the West [45].

Colorado has over 300 days of sunshine per year, making it an ideal location for solar photovoltaics and solar thermal technologies [46]. Colorado requires 4% of RPS requirements must be from solar and 2% of that must be from "on-site" solar systems (PV system) located at customers' facilities.

5.10.3.1 PV and Solar Thermal

Central station solar power technologies include both solar thermal electric and photovoltaic (PV) generators. The vast majority of the central station solar projects underway or actually deployed today are concentrating solar power (CSP) technologies, which as a class include all the thermal generators as well as concentrating PV. Flat-plate PV can also be used for utility-scale systems, but the much higher energy market values of distributed generation make it the more attractive deployment mode for flat plate PV today. As PV costs decline and its market volume grows, central station flat plate PV deployment will become more commonplace [45]. The WGA report cites a Solar Task Force survey of the CSP industry indicating capability to produce over 13 GW by 2015 if the market could absorb that much.

The Solar Task Force also projects that, with a deployment of 4 GW, total nominal cost of CSP electricity would fall below 10¢/kWh. Analysis shows that CSP at 10¢/kWh is equivalent to a blended base load-peak value of natural gas generation at a fuel cost of $7/MMbtu. Achieving 4 GW of CSP deployments by 2015 from the current 354-MW base requires growth similar to that of the PV and wind industries in the past decade.

5.10.4 Wind

Wind power has come a long way in the past decade. Today, advanced wind turbines make a major contribution in meeting renewable generation requirements of the utilities. In 2007, the total installed U.S. wind energy capacity reached 13.9 GW and the Colorado's share was 1.07 GW.[36]

In 2001, the Colorado PUC ordered Xcel Energy to include a 162 MW wind plant as part of its integrated resource plan [47]. The PUC concluded that the wind plant would cost less than new gas-fired generation under reasonable gas cost projections by stating:

> "We find that adding Enron's Lamar wind energy bid to PSCo's preferred resource plan is in the public interest and comports with the IRP rules. This determination is based solely on our finding that the acquisition of the Lamar facility will likely lower the cost of electricity for Colorado's ratepayers. After a careful analysis of the economics of the wind bid, we find that it is justified on purely economic grounds, without weighing other benefits of wind generation that could be considered under the IRP rules."

Since last large wind farm, Xcel has added 835 MW more wind resources to its resource portfolio to meet the minimal non-solar levels of the RPS requirements through 2020 and displace fossil-fired generation which reduces both gas and coal burns for electric production and the associated CO2 emissions. Xcel has also performed wind integration study to look at the cost of a 20% capacity penetration level of wind. This 20% capacity penetration equates to about 1.400 MW of wind, or about 350 additional MW of wind on Xcel system in Colorado. In its 2007 Resource Plan Xcel states:

> "...We do not believe that this 20% capacity penetration is a ceiling on the amount of wind that the system can accommodate. However, we do need to perform further studies and to look beyond the concepts in our studies to date to determine how we might modify system operation or plant generation in ways to allow cost effective integration of wind resources. Therefore wind additions beyond 2015 should be considered an indication of a desire to add additional wind resources in that tie frame rather than a firm commitment for those additions."

5.11 Near-Term Power Plants Retirements

Colorado's recent legislative mandates on power sector industry to add more energy efficiency programs and renewable technologies to their resource portfolio coupled with the statewide targets to reduce carbon dioxide emissions, have heightened

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[36] Information from American Wind Energy Association accessed March 2008. Available online at: www.awea.org.

utilities awareness on greenhouse gas emissions and utilities have started voluntarily to plan responsibly and retire old coal-fired plants. Xcel Energy in its 2007 Resource Plan proposes to retire six existing generation units and re-power them with natural gas combined cycle technology. The six units to be retired are listed in Table 23. In the Reference Scenario (BAU), a total of 353 MW of capacity is retired from the base year total installed capacity in 2005.

Table 23: Colorado Generating Capacity Retirement

Fuel Type	Plant	Capacity (MW)	Date
Bit. Coal	Cameo 1	24	12/2010
Bit. Coal	Cameo 2	54	12/2010
Steam Gas	Zuni 1	39	12/2009
Steam Gas	Zuni1 2	68	12/2012
Sub-Bit Coal	Arapahoe 3	47	12/2012
Sub-Bit Coal	Arapahoe 4	121	12/2012

Xcel Energy in its Resource Plan states the retiring these four coal units and re-powering them with a 480 MW Combine Cycle (CC) is expected to reduce CO2 emissions by 1.4 million tons per year.[37] These units are modeled as retired in the Reference Scenario and the decision to replace the units is made by the model which in the Reference Scenario (BAU) would be the same as Xcel Energy's decision that is a replacement of equal amount of capacity with conventional CC technology, however in Advanced and policy scenarios the decision would be based on the economics and carbon policy constraints.

5.12 Approved and Proposed Future Power Plants

Due to uncertainty and volatility in natural gas prices the coal-fired generation has re-entered as a viable option in the utilities' near-term resource portfolios. The Xcel Energy's new coal-fired power plant with a capacity of 750MW approved to be built in Colorado with a service date of 2009 is captured as an investment of $1.3 billion plus the transmission interconnection and delivery cost (i.e., $2020/kW in 2005$) in the model [18]. In addition, the possibility of building an additional 500MW coal-fired unit in Brush, Colorado (aka, Pawnee II) by 2014, reported in the study by Colorado Long Range Transmission Planning Group (CLRTPG), is not modeled but the model is allowed to choose economically the least-cost plant. Another 600MW coal-fired power plant, reported by Western Resources Advocates to be built in the southeast Colorado by Tri-State Generation and Transmission is not modeled as near-term definite resource addition.

5.13 New Power Plants

All new capacity decisions will depend on the costs and operating efficiencies of different options, fuel prices, and the availability of incentives such as Federal

[37] See Xcel Energy 2007 Resource Plan at

production tax credits for investments in wind technologies, and the carbon policy constraints. Natural gas plants are generally the least expensive capacity to build with lower CO2 emissions but are characterized by comparatively high fuel costs. Advanced clean technologies like IGCC, nuclear, and renewable plants are typically more expensive to build but have relatively low operating costs and, in addition, receive tax credits under EPAct2005, and meet the low carbon policy objectives.

The CEF report suggests a generation portfolio mix of approximately 3,000 MW of base-load power, 1,500 MW of intermediate power and 1,350 MW of peaking power to meet the growth. For this study, technology choices for new generating capacity will be made to minimize cost while meeting state's renewable and energy efficiency mandates coupled with climate action plan and other policy objectives. The model will make the choice of technology for capacity additions based on the least expensive options available subject to resource and policy constraints [21].

Table 24: Thermal and Renewable Resources Cost and Performance Data

Modeled Power Generation Technology	Capital Cost* (S/kW)	Life	Heat Rate* (Btu/kWh)	AF (%)	VAROM (S/MWh)	FXDOM (S/kW/yr)	Emission Rates* CO2 (lb/MWh) Output	NOx (lb/MWh) Output	SO2 (lb/MWh) Output	Source of Data DOE/EIA and EPA-NM updated from as noted below
New Biomass CC	1,634	30	10,283	80	2.99	45.04	-	-	-	
New PC with 50% CCS	3,769	40	11,343	93	10.58	46.21	1,167	0.3730	0.6191	Xcel Energy*
Com3 - Xcel Energy	2,020	40	8,672	88	3.06	15.64	2,159	0.0000	0.0000	Xcel Energy*
IGCC - Xcel Energy	4,008	40	10,202	88	3.05	17.14	1,048	0.4270	0.7048	Xcel Energy*
Bit Coal Steam	-	40	10,618	83	2.78	15.64	2,159	3.8953	2.3873	
Sub Bit Coal Steam	-	40	10,474	83	2.78	15.64	2,143	3.1810	3.7048	
DSF Steam	-	35	12,916	85	0.52	0.86	2,000	2.4683	0.1952	
Diesel IC	-	35	12,916	85	8.89	0.86	2,000	2.4683	0.1952	
New Geothermal	3,641	30	10,283	90	22.88	16.71	-	-	-	Xcel Energy*
Hydro	-	45	10,283	27	4.48	14.20	-	-	-	
Hydro PS	-	45	3,754	83	2.65	16.71	-	-	-	
New Coal IGCC with 50% CCS	4,008	40	10,202	87	3.05	17.14	1,048	0.4286	0.7064	Xcel Energy*
New Adv CT	520	30	8,553	92	2.83	8.89	921	0.0873	-	
New Adv CC	827	30	7,281	93	3.09	9.42	865	0.0714	-	Xcel Energy*
CC	-	30	7,399	94	0.49	15.75	881	0.1532	-	
New CC	885	30	7,463	95	2.81	13.19	889	0.3413	-	Xcel Energy*
CT	-	30	10,525	94	0.10	6.51	1,278	0.5683	-	
New CT	659	30	10,459	98	7.95	4.31	1,246	0.5175	-	Xcel Energy*
New Gas IGCC with 90% CCS	1,124	30	7,952	98	2.93	19.95	86	0.0794	-	
Gas Steam	-	30	13,390	92	0.52	0.86	1,587	2.4151	-	
New Adv Nuclear	2,897	40	10,512	92	0.60	58.00	-	-	-	
PV_Central	3,830	30	10,283	-	-	8.96	-	-	-	
PV_Rooftop	7,519	30	10,283	-	-	8.96	-	-	-	
Solar_Thermal	2,539	30	10,283	-	-	43.55	-	-	-	
Wind*	1,690	20	10,283	-	-	23.24	-	-	-	Xcel Energy*
Coal Based Imports*	-	-	-	-	-	-	2,159	-	-	
Gas Based Imports*	-	-	-	-	-	-	881	-	-	

Notes:

CC = Combined Cycle

CT = Combustion Turbine

PC = Pulverized Coal

IGCC = Integrated Gasification Combined Cycle

Com3 = Pulverized coal unit by Xcel Energy with no SO2 and NOx impact (net of other 2 units)

PS = Pumped Storage Hydro Facility

AF = Availability Factor

Heat Rate* = Renewables' heat rates are an equivalent proxy heat rate

Capital Cost* = Updated capital costs include transmission interconnection and delivery costs. For Solar, first year cost is shown, subsequent years costs are lower.

Wind* = Capital costs include PTC

Emission Rates* = Source of existing power plants emissions is EPA-ETS (Emission Tracking System)

Imports* = imports are transmission constrained at 5,100 GWh per year

Xcel Energy* = Operates as Public Service Company of Colorado filed its 2007 Resource Plan with Colorado PUC on Nov. 2007

The MARKAL database for this research contains 14 generating technology options for future capacity needs consideration. The model covers 30 years study period from 2005 to 2035 in three years increments. Table 24 shows the conventional thermal and advanced technologies including Renewable technologies utilized in the Reference Scenario and Advanced Technology Scenario.

The cost and performance characteristics of some of these resources were updated from Xcel Energy 2007 Resource Plan.[38] The complete lists of input data gathered from sources such as DOE and EPA models are given in Appendix C.

5.14 Discount Rate and Inflation Rate

Utilities use financial market risk measures to determine cost of capital or the discount rate for calculation of net present value of proposed capital investment decisions. By definition the appropriate discount rate for an investment is the opportunity cost of capital – the rate of return that investors expect in capital markets for the same degree of risk as the risk associated with the project being considered [48].

The discount rate is considered as global parameter within the MARKAL model to represent the time value of capital for energy systems investment from the societal point of view. The discount rate used in the Reference Scenario (BAU) is assumed to be at 7.5%. This is consistent with largest utility in Colorado, Xcel Energy's current discount rate of 7.88% based on after-tax weighted average cost of capital. As discussed in previous sections, IOU's serve close to 60% of Colorado's load and are the main drivers in generation resources capital investment in Colorado. Inflation rate of 1.5% is assumed for all commodity prices beyond 2008.

MARKAL also uses technology specific discount rate (or "hurdle rate"). In this study, the hurdle rate is based on the technology's life and the debt and equity capital structure for investment. EIA's fixed charge factors used for AEO2007 within the National Energy Modeling System is utilized to represent the technology specific hurdle rate.[39] Table 25 shows EIA's FCF for various technologies based on capital structure 45% debt and 55% equity and 38% tax rate and the respective depreciable life of each technology. The factors are utilized as technology hurdle rate for each technology within the model.

[38] It is assumed that Xcel Energy's data is more up-to-date than other sources and therefore is adopted for some technologies in this study.

[39] Data received through personal communication with EIA Staff Laura Martin.

Table 25: Technology Specific Hurdle Rates

Plant Type	Fixed Charge Factors
Scrubbed Coal New	16.23%
Integrated Gas Comb Cycle	16.23%
IGCC w/Sequestration	16.23%
Conv Combustion Turbine	13.68%
Adv Combustion Turbine	13.79%
Conv Gas/Oil Comb Cycle	15.42%
Adv Gas/Oil Comb Cycle	15.42%
Adv CC w/Sequestration	15.45%
Fuel Cells	15.42%
Advanced Nuclear	17.63%
Biomass (Wood)	13.24%
Geothermal	12.68%
Hydroelectric	15.81%
Wind	11.26%
Solar Thermal	12.02%
Photovoltaic	11.07%

Source: DOE/EIA

5.15 Transmission Constraints and Infrastructure Improvement Costs

The electric system in Colorado is covered by two control areas or regions: Colorado East (the front range) and Colorado West (west of the continental divide). Power flows into and out of Colorado are constrained by a set of transmissions lines. Power flow into Colorado from north is constrained by transmission lines limits known as TOT-3 limits, from the southwest (Four Corners) by TOT-2A limits, and from the West by TOT-1A limits.[40] The transmission between two Colorado regions is constrained by TOT-5 limits. Figure 22 shows Colorado transmission Constrained diagram.

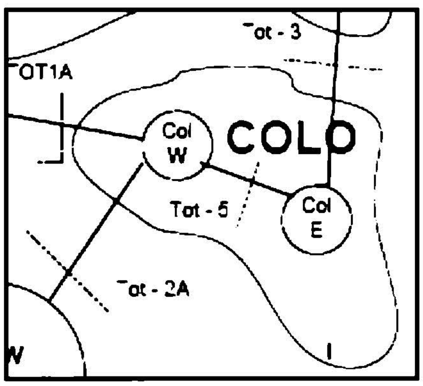

Figure 22: Colorado Transmission Constrained Diagram

[40] The term "TOT" is short for Total transfer capability of a set of transmission lines over a geographically defined boundary.

Table 26 shows the limits of the Colorado Transmission Constrained Paths. MARKAL is not an hourly model but allows imports and exports from and to a region to be modeled. Colorado does import and export power but in general is a net importer of power. The imports into Colorado are limited to TOT3 limits based on an annual average capacity factor of 40% or 5,100 GWh per year.

Table 26: Colorado Transmission Constrained Paths

PATH	PATH DESCRIPTION	RATING
TOT 1A	Utah to Western Colorado	E to W: 650 MW
TOT 2A	Four Corners to Southwest Colorado	N to S: 690 MW
TOT 3	Wyoming to Northeast Colorado	N to S: 1,450 MW
TOT 5	Western Colorado to Eastern Colorado	W to E: 1,675 MW

Source: CCPG[41]

In 2004, CLRTPG[42] forecast that over the next ten years, the demand for power will grow by 25% in Colorado's Front Range.[43] To meet such a demand, the CLRTPG study forecast that over 2,750 MW of new generation resources will be added in the Front Range and robust high-voltage transmission will be needed to convey the power to major delivery points.

Table 27 shows the overall transmission investment estimated by the CLRTPG representing a combination of budgeted and unbudgeted projects.

Table 27: Ten-Years Colorado Transmission Costs (Millions – 2004$)

Entity	Scenario 1 - 2750MW	Scenario 2 - 2750MW	Scenario 3 - 2750MW
Aquila	$37.9	$25.6	$37.9
CSU	$41.1	$23.4	$41.1
PRPA	$60.0	$60.0	$60.0
PSCo	$443.8	$227.6	$477.2
TSGT	$138.2	$75.3	$138.2
Western	$66.0	$103.3	$102.1
Total	**$786.9**	**$515.1**	**$856.5**

Source: CLRTPG

[41] Colorado Coordinated Planning Group for Transmission, http://ccpg.basinelectric.com/

[42] The Colorado Long Range Transmissions Planning Group (CLRTPG) consists of six entities. Western Area Power Authority and five Load-Serving Entities in Colorado; Aquila Networks, Colorado Springs Utilities, Platte River Power Authority, Tri-State Generation and Transmission, and Xcel Energy/Public Service Company of Colorado. CLRTPG was initiated in January 2004 to jointly explore the potential for the development of a "back-bone" transmission network in the State of Colorado that could benefit all electric LSE's in the state.

[43] Colorado Long Range Transmissions Planning Group, *Colorado Long Range Transmission Planning Study*, April 2004. CLRTPG available online at: http://www.rmao.com/wtpp/CO_Transmission_Planning_Group.html

Scenario 1 modeled the majority of new generation in the southern portion of the Front Range of Colorado which include Xcel Energy's new coal-fired power plant's transmission investment requirement. Scenario 2 modeled the majority of new generation in the Northern Front Range of Colorado. Finally, Scenario 3 modeled a balanced generation pattern (combination of Scenarios One and Two) in the Front Range of Colorado. CLRTPG report concludes "...the costs for Scenario Three may be more reflective of the actual long-term costs." For energy modeling, Scenario Three results are modeled as the transmission investment requirement of power generation capacity addition in Colorado. The input to the model for transmission investment for periods "between" 2011-2017 is $322 million (2005$) per GW. For all other periods, a uniform transmission investment requirement of $70/KW is modeled.[44] Transmission constraints from north (i.e., TOT3) have also been incorporated into the model as the upper bound of power generation imports into Colorado.

5.16 Resource Bounds

MARKAL model is an optimization model that is each decision variable has certain specified bounds and may fall between three categories:

- equal to its lower bound, or
- equal to its upper bound, or
- strictly between the two bounds.

The following resource bounds are incorporated in the model.

5.16.1 Power Imports

As discussed in section 5.15 above, Colorado does import and export power but in general is a net importer of power. The imports into Colorado are limited to TOT3 limits based on an annual average capacity factor of 40% or 5,100 GWh per year.

5.16.1.1 Market Prices of Imports

Prices for imports are adopted from electric market prices developed by Xcel Energy for on-peak and off-peak periods using the implied market heat rates at three locations (south of Colorado at 4 Corners, west of continental divide at Craig, and southwest power pool) and the estimated gas market prices.[45] The prices for Hydro and Renewable are assumed to be at 80% of off-peak and 120% of on-peak prices, respectively. However, for this study Hydro and Renewable import limits are set at zero only coal and gas based generations are allowed to compete with other resources. All market electric prices beyond 2030 were escalated implicitly at 2.33%

[44] Xcel Energy's 2007 Colorado Resource Plan models $70/kW as transmission investment requirements.

[45] Figure 1.7-2 of Volume 1 of Colorado Resource Plan filed November 15, 2007 before Colorado PUC.

based on the natural gas escalator as adopted by Xcel Energy. Figure 23 shows Market Prices forecast for import of power into Colorado.

5.16.2 Biomass Limits

The Western Governor's Association's Biomass Task Force estimates that Colorado has a potential generating capacity of 436 MW. In this study, about 173 MW of total 436 MW Colorado potential biomass generating capacity is utilized for co-firing with existing 1,733 MW bituminous coal fired capacity at ratio of 10 percent biomass and 90 percent coal. The remaining 267 MW of biomass potential generating capacity is made available for biomass gasification technology.

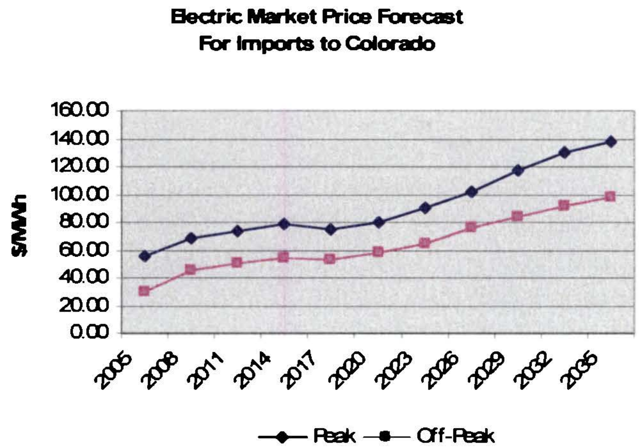

Figure 23 Market Prices Forecast for Power Imports to Colorado

5.16.3 Geothermal Limits

The Western Governors' Association's Geothermal Task Force estimates Colorado Geothermal capacity at 70 MW based on existing Colorado reservoir data. The study indicates the first 20 MW of Geothermal can be developed at $80/MWh and an additional 50MW of capacity could be developed at $200/MWh or less. Geothermal limit is set at 70 MW and the cost and performance data is shown in Appendix C.

5.16.4 Solar Limits

A Rule-Based constraint is designed to capture the RPS requirements in Colorado within the model. The percent requirement is modeled as a floor (i.e., a required bound since it is mandated) for the renewable generation in Colorado. The Rule Based constraint also recognizes the fact that the RPS requirements for solar generation shall include 4% from solar of which 2% shall be from distributed solar (i.e., rooftop solar).

5.16.5 Wind Limits

The Rule-Based constraint for renewables allows non-solar renewables to fulfill the RPS mandated requirements after taking under consideration 4% share for solar technologies. Since other renewable technologies such as geothermal and biomass have limited availability in Colorado, wind technology captures the majority of RPS requirements which reaches 16% of total electric sales by 2020. In the BAU scenario the RPS requirements is modeled as shown in Table 12. In Advanced Technology and Carbon Policy scenarios the RPS requirements is considered as the floor (i.e., the lower bound) but wind penetration is caped at 33% of total electric retail sales in 2035. This is mainly due to recent electric utilities independent studies that intermittent nature of wind generation could only be integrated into the utility system up to certain percentage of the utility generation. Beyond certain limits, the integration of wind generation becomes more costly thus less economical. For example, Xcel Energy recently performed a wind integration study for wind integration of 10% (722 MW), 15% (1038 MW), and 20% (1444 MW) into Xcel energy's system in Colorado and reported different integration costs and limits for its Colorado operation [49].

In this study, for the carbon tax scenario, the wind constraint had to be relaxed to see the impact of the carbon tax on the entire system.

In the following section, the results of scenario analysis are documented.

6 SCENARIO DESIGN AND ANALYSIS RESULTS

This study looks at Colorado's energy needs, existing power system, and the many factors involved in achieving maximum economic and societal benefits from electricity production at minimum cost. In addition to traditional considerations of fuel type and generation capacity, policymakers today must take into account the affects of renewable portfolio standards, demand-side management strategies, and various measures to improve energy efficiency. Based on our in-depth analysis and projections, we offer several quantifiable pathways Colorado could use to achieve sustainable energy production and minimize harmful emissions in the future.

Colorado's burgeoning population and fast-growing economy trend toward ever increasing demand for energy services in 2005-2035 (Figures 9 and 10). During the 1990s Colorado's population grew by over 30%. In July 2006, the state had 4.75 million residents and a population growth rate that is third in the nation. Over the next decade, moreover, it is projected to add a million new residents. [46]

In 2005, per capita electricity usage in Colorado was 10.4 MWh a year and sales were 0.217 KWh per state GDP. In 2004, the state registered 828 MT of CO2 per each GWh of electricity generated. Yet by early 2007, Colorado's renewable generation capacity (excluding hydro) amounted to only 298 Mw. (Table 28)

Table 28: Colorado Statistical Population & Generation Information[47]

Population July 1, 2006	4,753,377
KWh sales per person (2005)	10,365
KWh sales per dollar of state gross Domestic product 2005 (2006$)	0.217
CO2 emissions per GWh generated 2004 (metric tons)	828
MW of renewable energy generating Capacity early 2007 (excluding Hydropower)	298

Demand for energy services drives estimates of future requirements for electricity generation over time, and concomitantly, of required added power plant capacity (see Section 5.3 above). Figure 24 shows the composition of aggregated demand for

[46]Colorado Alliance for Immigration Reform. Available online at: http://www.cairco.org/data/data_co.html

[47] Western Resources Advocates, available online at: http://www.westernresourceadvocates.org/media/pdf/State%20Clean%20Energy%20Policies%20May%202007.pdf

energy by sector. In Colorado, the commercial sector dominates usage, followed by the residential and industrial sectors.

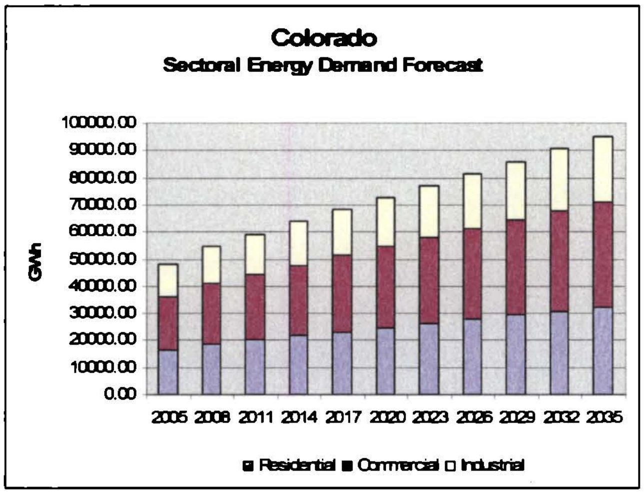

Figure 24: Colorado Sectoral Energy Demand

6.1 Energy Supply

With primary energy use in the sate consistently on the increase, by 2035 Colorado will need 87% more electricity. For the domestic and imported supply of energy for the BAU scenario, see Figures 25.

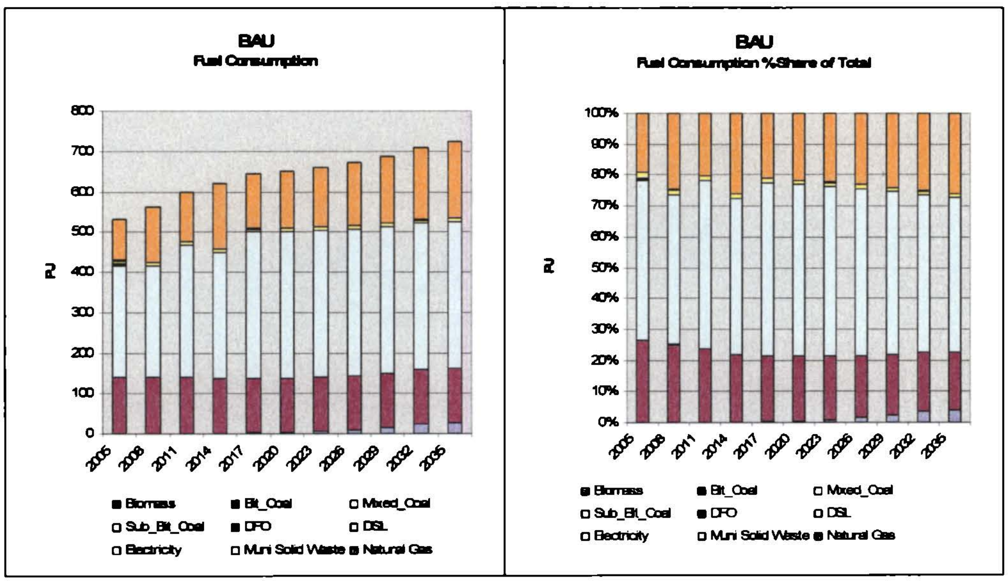

Figure 25: Reference Scenario (BAU) Primary Fuel Consumption

Coal currently provides the bulk of the state's energy generation, followed by natural gas, with a minimal role for oil and liquid fuel. Other sources (such as biomass) will play a role in the out years. At night electricity is used to pump water to storage facilities for generation during the day peak hours.

Two new coal-fired power plants, with in-service dates modeled as 2011 and 2017, will increase coal generation from 2005 levels. While coal currently dominates electricity generation, therefore, it is projected to play an even larger role into the future, peaking in 2035 at 46,000 GWh of the state's total generation requirements (Table 29, Figure 26).

Table 29: Reference Scenario (BAU) Generation Mix by Fuel Type

Fuel Type	DOE/EIA 2005	Model Output (GWh) 2005	2020	2035
COAL	35,570	37,328	45,947	45,947
HYDRO + PS*	1,415	3,499	3,615	3,632
GAS	11,923	11,366	16,489	22,585
OIL	17	400	0	0
RENEWABLE+MSW	810	875	12,699	33,006
IMPORTS	-	2,403	1,417	0

PS* = Pumped Storage with 2,172 GWh Generation included in Hydro + PS. EIA data is only for Hydro Generation

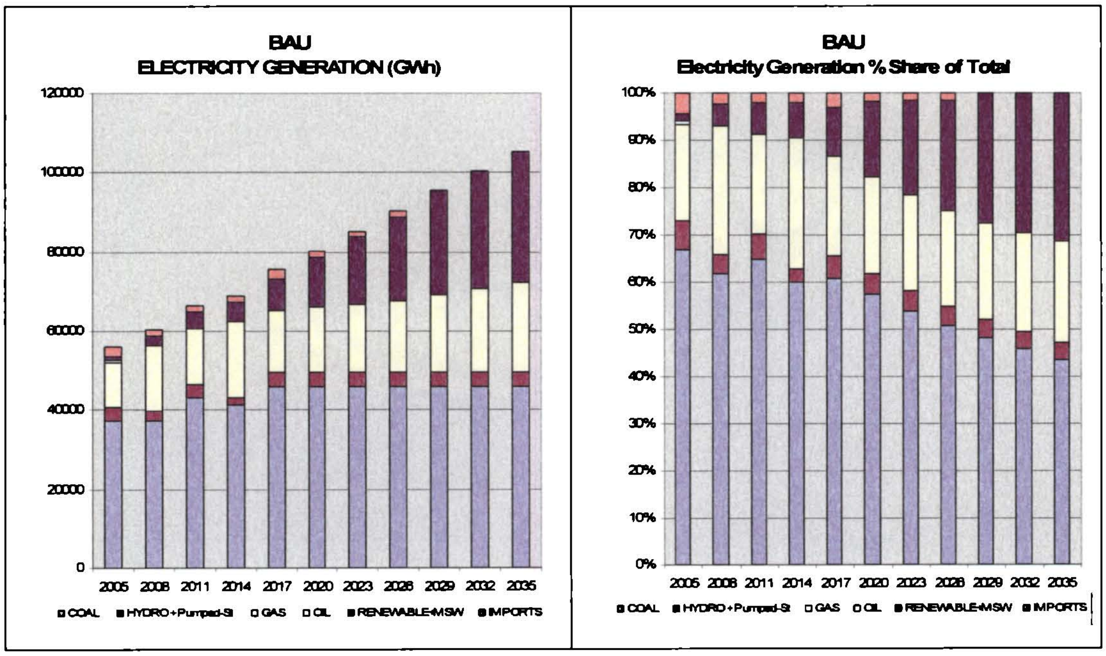

Figure 26: Reference Scenario (BAU) Electricity Generation

In this scenario, gas generation increases over the years and doubles by 2035. This is mainly due to the fact that all new capacity additions will be gas-fired. The hydro generation of 3,500 GWh in the reference scenario includes 2,172 GWh of generation from pumped-storage facilities in the peak hours. Table 29 also shows that the Reference Scenario (BAU) generation level is within +/- 4% of reported DOE/EIA generation levels, which means the Reference Scenario (BAU) is calibrated very closely to the actual status in 2005 and reflects a realistic scenario for Colorado's power sector in the future.

In 2005, coal (including about 4% of coal-based generation imports into the state) accounted 71% of the Colorado's total electricity generation. Yet in the BAU scenario, the projected share of renewables consistently increases over the years until in 2020, they meet the RPS requirement of around 16% of production (see Section 5.8.1 and Table 30). It should also be noted that in the out years, when renewable (especially wind) technologies will be more competitive, the model shows the use of renewables well above RPS requirements. It should be noted that in the model, RPS requirements were set as a floor, not a ceiling.

Table 30: Percent Share of Generation by Fuel Type

Fuel Type	2005	2020	2035
COAL	66.7%	57.2%	43.6%
HYDRO + PS	6.3%	4.5%	3.4%
GAS	20.3%	20.5%	21.4%
OIL	0.7%	0.0%	0.0%
RENEWABLE+MSW	1.6%	15.8%	31.3%
IMPORTS	4.3%	1.8%	0.0%

Other major sources of energy for electricity are oil and imports. In the BAU, oil consumption for electricity generation in 2005 was less than 1% and came mostly from small power generators owned by utilities or municipalities. Imports (4% in 2005) generally come from existing long-term utility contracts. By 2020 when most of these will have expired, imported energy is expected to account for only 1.8% of consumption, and it is projected be completely phased out by 2035.

In the Reference Scenario (BAU), renewables and gas-fired generation will gradually add to Colorado's generation fleet. It is therefore projected that coal consumption will decrease to 57% by 2020 and to 44% by 2035. The BAU projects:

- retiring 350 MW of old coal-fired generation in the next decade;
- adding new pulverized coal-fired generation of 750 MW (in service 2010);
- adding 600 MW of IGCC technology with 50% carbon capture technology (in service 2017).

The source of hydro generation includes both private and federally owned hydro and pumped-storage facilities, which accounted for 6.3% of generation in 2005 and is

projected to drop to 4.5% in 2020 and 3.4% by 2035. This is due to the fact that there are currently no plans to build hydro power plants in the next 30 years, mostly because of licensing requirements.

Other sources of renewables energy such as wind and solar, are projected to cover most of the increased need for electricity in the next 30 years. In 2005, renewables (mostly wind generation) only covered 1.6% of total energy needs. Wind generation is projected to increase to 8% by 2020 and to 24% by 2035. There was no significant solar generation in 2005, but by 2020 solar is projected to account for 3.1% of total Colorado's electricity generation, and by 2035 it should reach 4.3%. This is in part the effect of RPS requirements, which require utilities to acquire or generate a certain percentage of their sales from renewable sources (see Tables 12 and 20).

6.2 Installed and New Capacity Addition

In 2005, the total installed generating capacity in Colorado was 11.22 GW, of which 45.8% was coal-fired, 38.6% gas-fired, 2.4% oil-fired, 5.7% hydro, 5.0% pumped-storage, and 2.4% wind generation capacity (Figure 27).

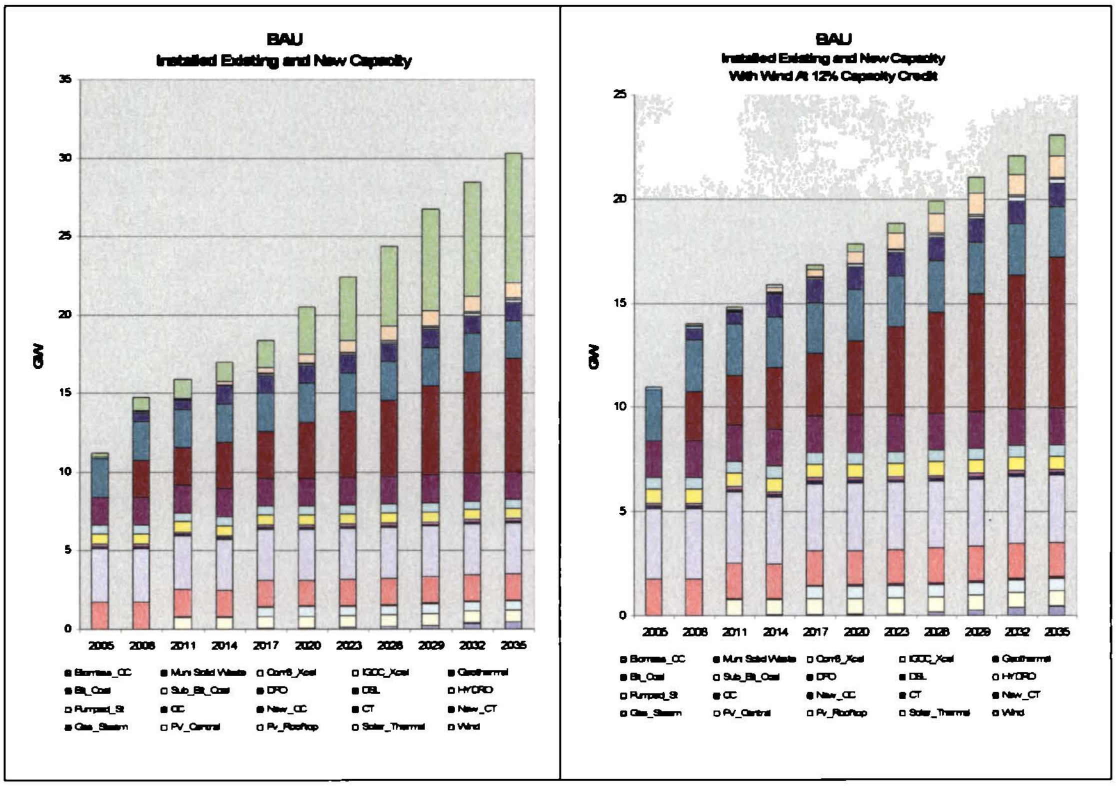

Figure 27: Reference Scenario (BAU) Installed and New Capacity Additions

In 2020, coal's share of capacity is projected to drop to 30.7%, of which 6.5% belongs to new coal-fired units. Gas-fired generation capacity increases to 43.4%, of which 20.6% belongs to old combined cycle (CC) and combustion turbine (CT) generating capacity, with 17.4% new CC, and 5.4% new CT. Renewables share generating capacity should increases to 19%, of which: 14.9% is wind technology, 3.5% solar technology, and 0.7% biomass and geothermal technology. By 2035, the renewables should account for 33% (of which, 27% is from wind technology), 4.3% solar technology, and 1.7% biomass and geothermal technologies. At the same time, coal-fired generating capacity should fall to 20.8%, while gas-fired generating capacity will keep its share at 41.4% (23.8% new CC, 3.6% new CT) of the state's total generating capacity.[48]

Figure 27 shows the portfolio of generation mix — which includes a sizeable amount of renewable technology by 2035 — to meet the state's projected needs, while meeting the RPS requirements, and least-cost criteria of the model. By 2035, added new wind capacity (about 8.2 GW), which will accounts for 27% of total generating capacity, can be given credit for only <1 GW of effective load-carrying capability.

The correct assessment of *capacity credit*' for wind-generated power has been the subject of disagreement in many jurisdictions. Capacity credit is based on a reliability metric, known in the industry as a plant's 'effective load-carrying capability' (ELCC). Several studies applied the reliability metric to wind power plants to assess their effective capacity credit [58]-[59]. Theses studies estimate wind power's capacity credit at 20-40 percent of the rated capacity of the wind plant. Colorado adopted ELCC in the first competitively bid, large-scale wind project to come before the Colorado PUC [47]. Xcel Energy in Colorado uses 12% as its ELCC for wind plants and in resource plans. Figure 27 for a side-by-side comparison, that shows a very different profile for wind generation depending n the method used to calculate capacity credit.

When the current wind technology capacity credit is applied, Colorado's total amount of new capacity added in each period meets the state's firm load obligation, the projected demand forecast, plus a planning reserve margin of 22% to insure reliability of power supply (Table 31). Because our model uses a higher margin to cover losses and any difference between levelized summer demand and actual peak demand, it builds in 8-10% more capacity than the forecasted-demand-plus-22%-planning-reserve method.[49]

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[48] In Reference Scenario (BAU), model prefers CC technology to CT from total system cost point of view and inefficiency of CT technology. In Advanced technology scenario, model prefers advanced CT technology again because of total system cost point of view and more efficient CT technologies.

[49] Transmission losses of 6.5% are used as input to the model.

Table 31: Firm Load Obligations Compared to Model Output (GW)

Year	Forecast	Forecast + 22% Planning Reserve	Model Output
2008	10.39	12.68	13.99
2011	11.18	13.63	14.82
2014	11.96	14.59	15.89
2017	12.75	15.55	16.83
2020	13.53	16.51	17.84
2023	14.32	17.47	18.85
2026	15.10	18.43	19.92
2029	15.89	19.39	21.05
2032	16.68	20.34	22.07
2035	17.46	21.30	23.06

In the model, a reserve margin of 35% is chosen for Colorado grid, as a percentage of the summer peak demand. Note that the reserve given by the user in the model is typically much larger than prevailing rule-of-thumb values used by the electric utilities (e.g., 22% used above as planning reserve which was added to demand forecast and compared with new capacity additions built by the model). Reason for this is that the reserve margin in MARKAL also encompasses the difference between the levelized summer (or winter) demand and the actual peak occurring on one moment in that same period when the demand is actually the highest.[50]

6.3 Reference Scenario (BAU): Projected Emissions Profile

The model's CO2 emission output for 2005, the model's base year, closely matched DOE/EIA and EPA reported emissions (Table 32). The model also includes all CO2 emissions from coal or natural gas based electricity imported into Colorado. Model emissions of criteria pollutants are also within close range of reported emissions.

Table 32: Base-Year (2005) Emissions

Source	EMISSIONS		
	SO2 (kt)	NOx (kt)	CO2*(kt)
DOE/EPA Reports	54-58	61-67	41,000- 42,000
Model Output	55.2	58.7	43,605
Note: CO2* Emissions include Imports Emissions of 1,781 kt.			

Figure 28 shows the Reference Scenario (BAU) CO2 emissions profile for all installed and new capacity additions. By 2020, the level of CO2 emissions increases by 17% from 2005 levels to 51,122 MT. This is mainly due to increased demand for energy and the addition of two new power plants, one with no carbon-capture

[50] See MARKAL user manual. Available online at: http://www.etsap.org/tools.htm

technology and the other an IGCC plant with 50% carbon-capture. The level could have been still higher if RPS mandates were not in place. In the BAU, the RPS required 16% effective rate is reached by 2020, so that by 2035, CO2 emissions increase to only 52,149 MT, which is up 2% from 2020 levels

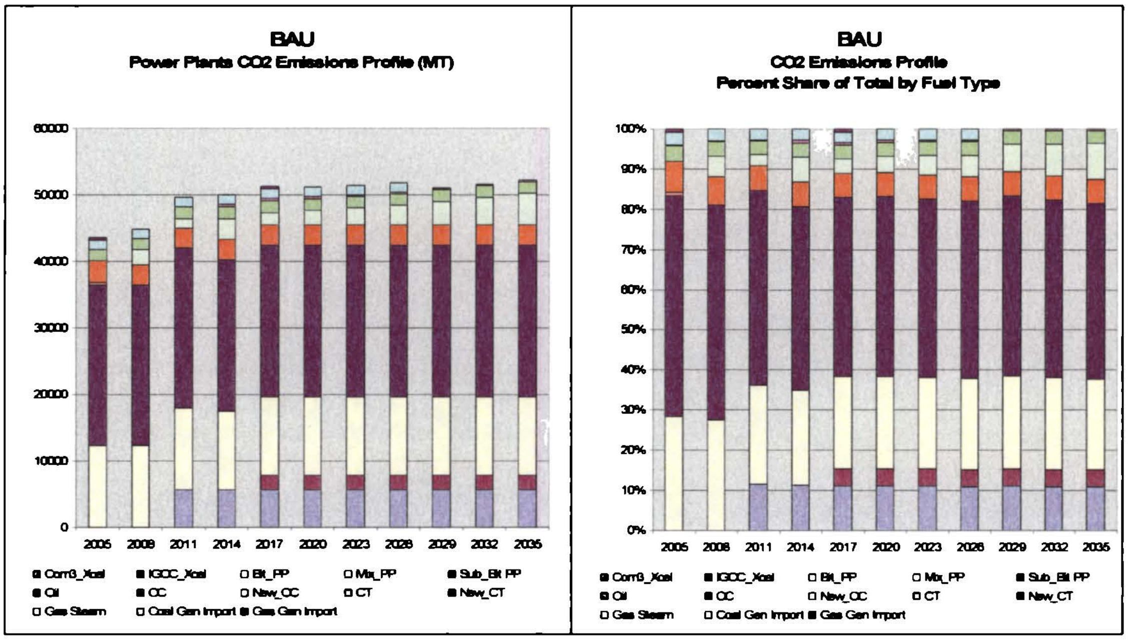


Figure 28: Reference Scenario (BAU) Projected CO2 Emissions Profile

In Colorado, coal generation contributes more than 80% of CO2 emissions throughout the modeling horizon. Because coal units are the most economical to operate, the model uses all installed and new coal power plants to their maximum level of availability at all hours. Under the Reference Scenario (BAU), the CO2 levels reach 52,000 MT by 2035. But as RPS requirements are increasingly met over time, fewer fossil-fueled generation capacity is added and more demand is met by renewable technologies. This change in the power generation mix puts the brakes on the increase in CO2 emissions in Colorado, but RPS requirements alone cannot decrease the CO2 emissions level unless other constraints such as carbon policy scenarios are introduced. In the following sections carbon policies and their impact on the pattern of coal units utilization is discussed.

6.4 Advanced Technology Scenario

This study evaluated a total of 6 advanced technologies:*

- *Pulverized coal with carbon capture and sequestration (CCS).* Equipped with (CCS), conventional pulverized coal-fired technology is considered to be at 50% of CO2 capture capability.

- *Integrated Gasification Combined Cycle (IGCC)* technology is a power generation process that integrates a gasification system with a conventional combustion turbine. It uses coal or natural gas to generate electricity from a combined-cycle power block. Coal-fired IGCC technology is considered to have 50% CCS capability. Natural gas-fired IGCC is considered to have 90% CCS capability.
- *High efficiency advanced combined cycle.* Powered by natural gas
- *High efficiency combustion turbines.*
- *Advanced nuclear technology.*

*Although state utilities are seriously considering nuclear generation as a viable option to reduce CO2 emissions in the near future coupled with advanced CCs and CTs, their first availability is projected no earlier than 2014 which is the first year availability incorporated in the model. See Table 24 and Appendix C for detailed cost and performance data on all technologies considered in the model.

6.4.1 Energy Supply

Comparing the reference (BAU) and advanced technology scenarios (Figure 29), we see that advanced technologies use less fuel (in this case, natural gas) to generate the same amount of electricity.

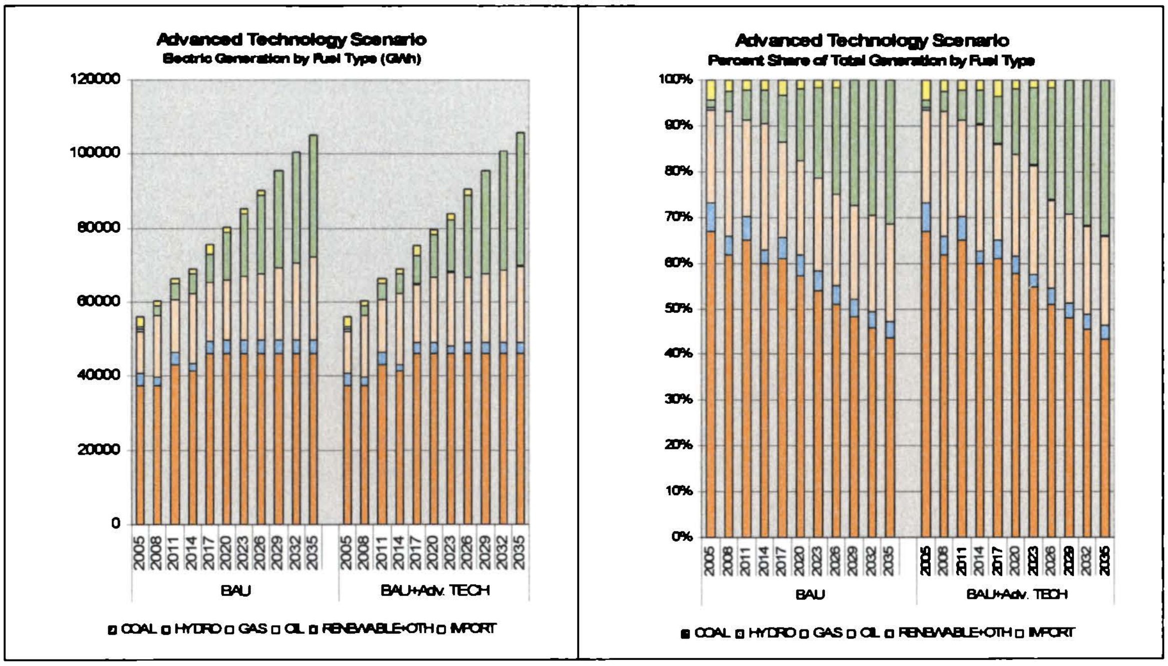


Figure 29: Advanced Technology Scenario Electricity Generation

It should be noted that in the out years, as more advanced technologies become available thus more cost-effective, their share of the energy production increases.

6.4.2 New Capacity Additions

Figure 30 compares the BAU and advanced technology scenarios with regard to new capacity additions. Beginning in 2014, when new technologies are projected to become more widely available, the model incorporates the use of more Combustion Turbines (CT). With higher efficiencies and lower costs[51], advanced CTs can operate fewer hours than are projected for conventional CCs in the reference scenario (BAU), and renewables technologies supply the energy formerly produced by the now displaced CCs (Figure 29).

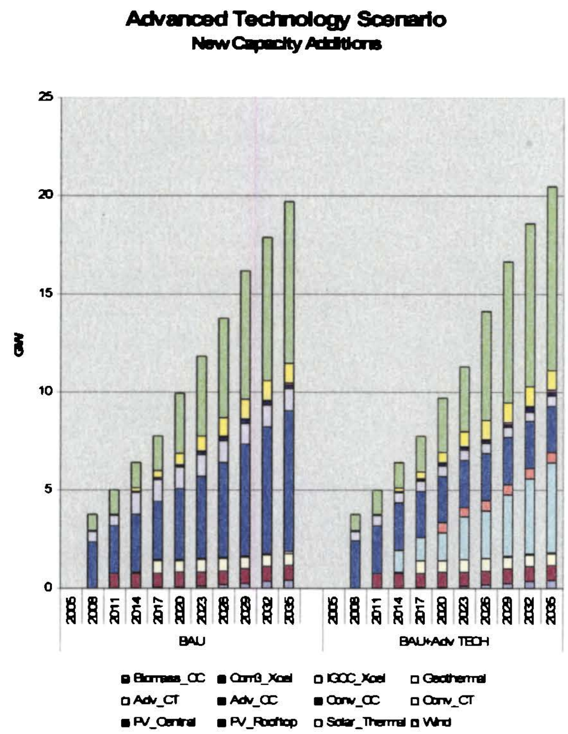


Figure 30: Advanced Technology Scenario New Capacity Additions

Once more efficient advanced technologies become widely available Figure 30, new capacity additions are met by CTs. This means investments are made to meet just the high (or 'needle') peak demands. It also means that the need for added investment can be prevented by any type of demand-side management (peak-shaver) or energy efficiency measures.

[51] Improvements in efficiency and costs for Advanced CT make it more cost effective to operate in the out years.

6.4.3 System Costs and CO2 Emissions Profile

According to the advanced technology scenario, as more energy-efficient technologies are introduced into the generation mix, both system cost and the CO2 emissions profile will be slightly reduced in the out-years. The discounted total system cost reduces by 1.1% compared with the BAU scenario, and the growth in CO2 emissions will slow slightly as renewable energy sources begin to displace fossil-fueled CCs' generation and more advanced CTs are used to meet peak demand (Figure 31).

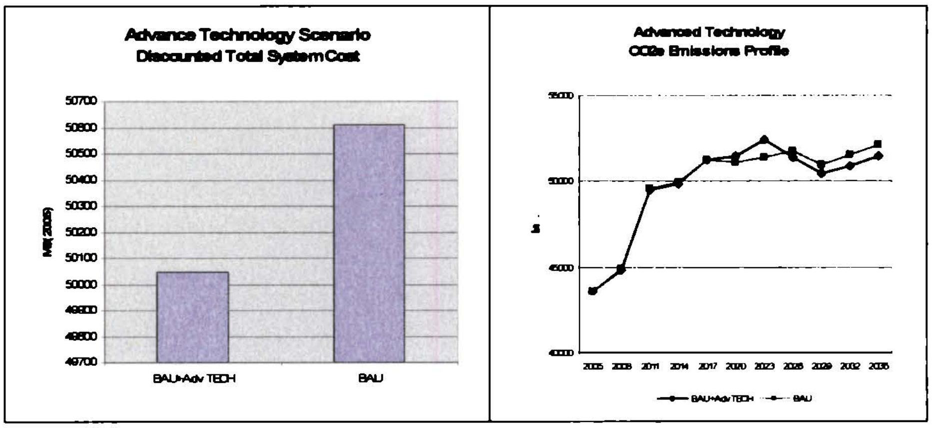


Figure 31: Advanced Technology Scenario Costs and CO2 Emissions Profile

In the remaining portions of this study, the advanced technology scenario is considered as BAU on the assumption that, as advanced technologies become available, they will be incorporated during the normal course of business to improve efficiency and lower costs.

6.5 Energy Efficiency and CO2 Emissions Reduction

In the 1980s, energy sector economists introduced the paradigm of energy-efficient resource use. More efficient means of production would generate '*nega*watts,' argued Emory Lovins, and thereby reduce the need for new plants to meet end users' power demands [56].

While utility companies have been well aware of the energy efficiency argument for the past three decades,[52] deregulation and increasing competition in the electric utility industry during mid-1990s led many to cut costs and spend less on demand-side management (DSM) [39]. In the national (and international) debate on strategies

[52] Utilities have been involved in energy efficiency programs since 1973 Arab oil embargo which continued throughout 1980s and 1990s but started dwindling down during the electric industry restructuring. Recent uncertainties regarding greenhouse gas regulations appears to jump started energy efficiency programs by states and utilities responding more favorably to energy efficiency programs again.

to reduce greenhouse gas emissions, DSM programs are considered viable options for reducing CO2 emissions in utilities resource plans [50].

The terms '*energy conservation*' and '*energy efficiency*' are often used interchangeably in policy discussions, although they are not in fact the same. *Efficiency* entails doing more with less, while *conservation* means doing without. Energy efficiency is the ratio of energy services output (say, electricity) to energy input (say, coal) and is a measure of how much energy is produced for every unit of energy consumed to make it. Better technology is required to improve energy efficiency, while to raise the level of energy conservation requires regulation and a change in consumer lifestyles and energy consumption behavior [51].

Some argue that consumption has increased because production has become more efficient, resulting in lower prices. Boardman comments that substantial improvements in energy efficiency have been passed on to the general economy in the form of greater productivity:

> "The substantial improvements in energy efficiency have been absorbed into more and larger product. At some stage, society needs to recognize that ever-higher standards of living are threatening our ability to limit climate change and, therefore, reducing our future quality of life." [52]

Herring similarly argues that higher energy efficiency has a 'rebound effect' of driving up higher consumption [51]. Three categories of rebound effect have been described: [53]:

1. *Direct effects*, which stem from consumers' natural tendency to use more of any low cost product or service;
2. *Indirect effects,* such as lower energy costs' spur to the economy, which creates more income and leaves more income available to spend on other products and services — some of which (such as travel) consumes more energy;
3. *Economy-wide effects,* long-term changes in the economy caused by technological innovation and changes in consumer preferences and behaviors, which is brought about by the substitution of relatively cheap energy for other factors of production.

According to Herring, even cost-effective and energy efficient lighting has a rebound effect. Studies of the Compact Florescent (CFL) bulbs, for instance, suggest that about a third of users choose to leave CFL lights on longer and to install additional CFL lighting, because it uses less energy, in the garden or for security. See [51], p. 201. Herring concludes with the question "Does innovation to produce more energy-efficient products and systems lead to lower energy consumptions?. . . This depends

upon the extent of the 'rebound,' which effect is difficult to measure on a national or macro-scale."

In Colorado, the regulated utility Xcel Energy was required to conduct a market potential assessment of various DMS and energy efficiency measures.[53] The goal was: "To conduct a market study to determine levels of efficiency available for various customer classes, the costs associated with such measures and whether such levels of DSM are cost-effective and available in Colorado."

The study estimated potential savings in electricity and peak demand from DSM measures in Xcel Energy's Colorado service territory.[54] The study covered savings in new and existing residential and nonresidential buildings, as well as from making industrial processes more energy efficient. The original study was restricted to DSM measures presently available commercially and covered the 8-year period 2006–2013. This period was later extended to 2015 to allow Xcel Energy's resource planning activities to harvest the results.

Primary data collection for the study involved 300 residential on-site surveys, 152 commercial on-site surveys, and 193 vendor telephone surveys. Secondary sources included several internal Xcel Energy studies and data, as well as a variety of information from third parties.

The study identified baseline end-use and developed estimates of effects from future energy efficiency gains using varying DSM programs. As part of the baseline, the study identified the types and approximate size of various market segments with the greatest DSM potential in Xcel Energy's Colorado service territory. These characteristics then served as inputs for a modeling process.

The bulk of the analytical work for this study was carried out using a model developed for studies of energy-efficiency potential. The model was a spreadsheet model that integrated data on technology-specific engineering with that on customer behavior and utility market saturation, load shapes, rate projections, and marginal costs. The study used the *Total Resource Cost* (TRC) test screen DMS measures and considered electric utility avoided-cost benefits only [40].

To evaluate and justify potential benefits from energy conservation, researchers generally use a supply-side planning model where utility marginal costs are the yardstick against which conservation program costs are judged [54]. Under this framework, technologies or practices that reduce energy use through efficiency are characterized as "liberating" supply for other useful energy demands. These energy efficient technologies are therefore thought of as a supply resource and plotted on an

[53] Xcel Energy is doing business as Public Service Company of Colorado.

[54] Colorado DSM Market Potential Assessment, KEMA, 2006.

energy supply curve. In this study, we used this technique to assess the cost and benefits of DSM and energy efficiency measures.

6.5.1 Statewide DSM/EE Plans

In past years, Colorado's regulated and non-regulated utilities have actively pursued DSM programs. For example in 1993, Colorado utilities spent 0.40 percent of their revenues for DSM programs, with an estimated savings of 0.53 percent of sales. DSM activities dropped off in late1990s, mostly due to increased competition in the electric utility industry following restructuring era [39]. In 1998, for example, Colorado spent 0.11 percent of state electricity sales revenues for DSM programs, which resulted in estimated savings of 1.29 percent of sales. Comparing 1998 to 1993 DSM activities; a total of 0.29 percent reduction in DSM related expenditures from 1993 spending levels occurred in 1998 but, the savings as percent of sales were higher, 0.73 percent change from 1993 sales level [55].

6.5.2 Cities and DSM/EE Projects and Costs

Aside from utility DSM programs, cities and municipalities that provide electric services to end-users have also been active in DSM/EE programs for many years. For example, Seattle City Light (SCL) has been active in energy conservation programs since 1979 and continues to provide energy efficiency programs to residential customers. In 2002-2004, SCL sought to secure Bonneville Power Administration funds, under the conservation agreement for residential energy sector, by focusing on conservation projects eligible for power purchase offsets. In 2004, SCL secured 1.1 MW from energy-saving residential projects. SCL reports that it cost $102/MWh on average to accomplish Energy Conservation for Multifamily Residential housing during 1986-2004 and $79/MWh on average for the Built Smart project of 1992-2004 [57].

Recently, many cities and municipalities that do not provide electric services to their citizens have become actively involved in DSM/EE programs to provide incentives to reduce electricity consumption. One direct benefit of reduced consumption is a smaller greenhouse gas footprint for these cities [e.g., Boulder, Aspen, and Seattle].

6.6 Aggressive DSM/EE Scenario

This study modelled two aggressive DSM scenarios independently. Both posit that that recent climate action plans at the city and state level require Colorado utilities and municipalities to work together to reduce electricity consumption, particularly if they are to achieve the target CO2 reductions by specified dates. First, it is assumed that Colorado utilities' efficiency programs will result in the reduction of 300 GWh a year, beginning in 2008 and accumulating over the planning horizon. It is further assumed that the penetration rate in the three major energy using sectors is

commercial (65%), residential (25%) and industrial (10%).[55] In this aggressive scenario, the accumulated total energy savings over the planning horizon would be 9,000 GWh.

It was further assumed that cities and municipalities will institute more stringent building codes and energy conservation programs, which will result in a 1% per year reduction in energy demand. The goal is to reduce electricity consumption by 30% by 2035. The same sectoral distribution factors commercial (65%), residential (25%) and industrial (10%) used in the first aggressive DSM scenario obtains for the second scenario as well. Over the planning horizon for this scenario, The accumulated total energy saving would be 14,200 GWh by 2020 and 28,400 GWh by 2035.[56] This conservation goal is consistent with SWEEP[57] four-prong energy efficiency goals for 2005-2020. The reductions goal for each of proposed program is as follows:

- DSM (7,323 GWh)
- Building Code (1834 GWh)
- Lamps Standards (3784 GWh)
- Industrial Option (1733 GWh)

TOTAL = 14,674 GWh by 2020
[NREL study for RMCO].[58]

As discussed above, the average DSM/EE costs (including rebates and administrative costs paid by municipalities to accomplish energy efficiency programs) is on the order of $60-90, depending on the location and the type of conservation program. For example, Seattle City Light's average conservation program cost the city some $90 per MWh for residential customers (cost to utility not TRC) [57].

[55] Recent study by Xcel Energy shows a penetration rate of 75/25% for commercial and residential customers, respectively.

[56] The total conservation of 28,400 GWh is 30% of Colorado total base case energy demand forecast of 95,000 GWh for 2035.

[57] Southwest Energy Efficiency Project, http://www.swenergy.org/

[58] NREL performed a spreadsheet analysis for Rocky Mountain Climate Organization (RMCO) incorporating Southwest Energy Efficiency Program proposed DSM/EE measures.

Table 33: Reference Scenario DSM Costs

Year	Annual Average ($/kWh)	Maximum Hour ($/kWh)
2008	0.053	0.105
2011	0.037	0.118
2014	0.036	0.102
2017	0.052	0.126
2020	0.070	0.169
2023	0.093	0.226
2026	0.125	0.303
2029	0.168	0.405
2032	0.224	0.543
2035	0.301	0.727

Source: Xcel Energy DSM Docket

In this study, Xcel Energy's maximum-hour avoided marginal energy prices are used as the Total Resource Cost of the DSM programs, since Xcel Energy is the largest electric utility actively pursuing DSM measures in the state. (Table 33)

6.6.1 DSM/EE Scenario Electricity Generation

Figure 32 compares generation levels with DSM/EE measures and BAU with no such measures.

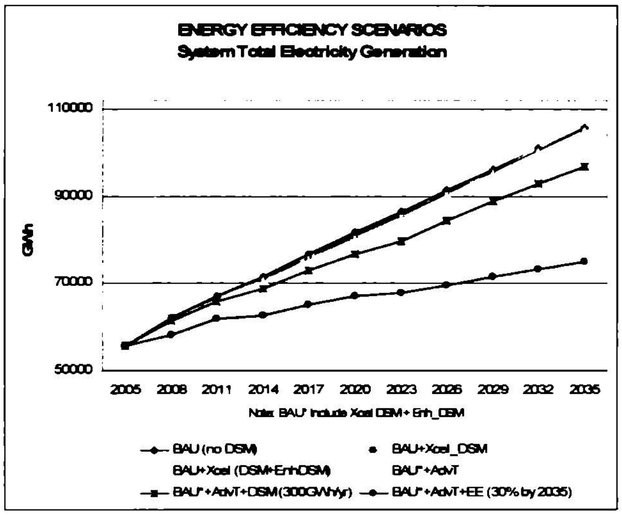


Figure 32: DSM/EE Scenarios Total Electricity Generation

As expected, aggressive DSM/EE measures substantially reduced total energy generation, with the most aggressive Energy Efficiency program cutting energy generation by 30% in 2035. Potential costs and benefits, in the form of CO2 reductions, are discussed in the following sections.

In considering electricity generation by fuel type, the patterns of generation from coal do not change much when DSM and other energy efficiency measures are introduced, because coal is already the least-cost fuel and is not at margin to be affected by such measures. The major expected contribution of aggressive DSM/EE measure is a reducing investment in new capacity and lowering fuel costs associated with generating units that are at the margin, such as natural gas CT generating units (Figure 33).

Figure 33 also shows the level of generation from natural gas and renewables. As more aggressive DSM/EE measures are introduced, less generation from gas-fired units are used. The same is true with renewables. Since the amount of renewables is based on RPS requirements (a percent share of total sales of electricity), as energy demand diminishes over time, less is correspondingly required from renewable sources.

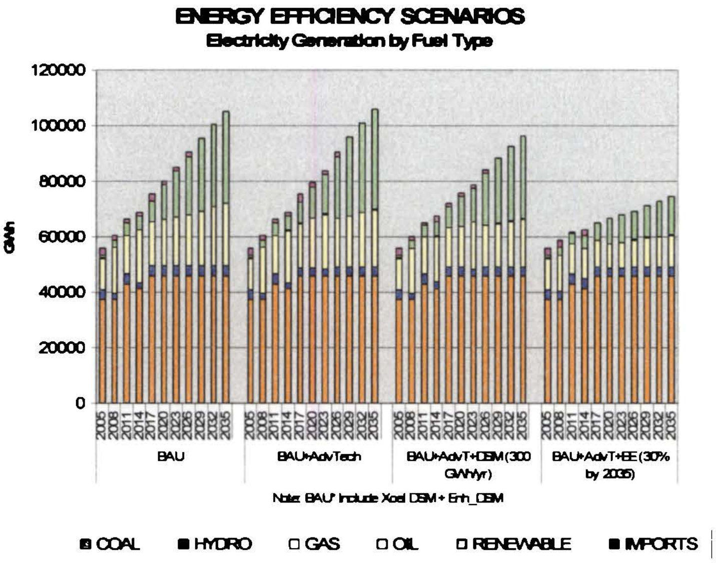


Figure 33: Energy Efficiency Scenarios Generation by Fuel Type

6.6.2 New Capacity Additions

One of the main objectives of investing in more DSM/EE measures is to reduce demand and build fewer new plants and other energy infrastructure than would otherwise be needed. Figure 34 shows how, in the aggressive DSM/EE scenario new capacity additions decrease as more aggressive energy efficiency measures are instituted. By 2035, for instance, it is projected that a 1 percent a year savings from energy efficiency measures will be matched by a 45 percent drop in Colorado's new capacity additions (excluding wind technology) as compared with the BAU scenario.

Including wind technology, the need for new capacity decreases by an astonishing 59 percent by 2035.

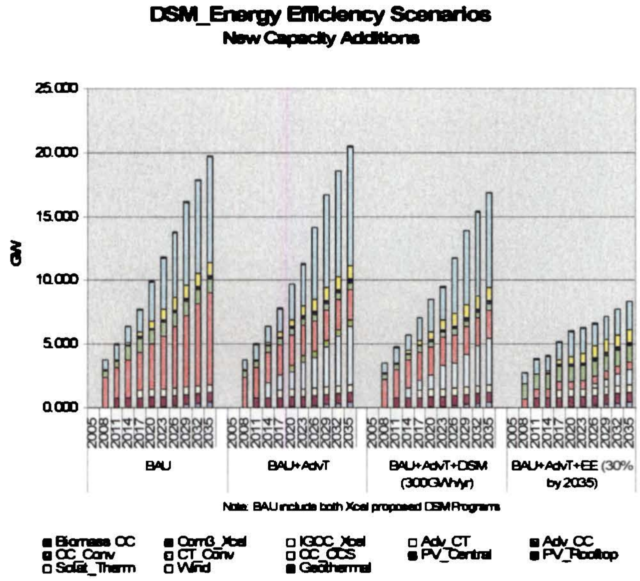
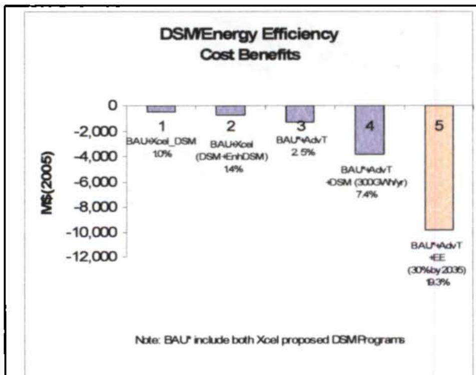


Figure 34: Aggressive DSM/EE Scenarios New Capacity Additions

6.6.3 DSM/EE System Cost-Benefits

Figure 35 compares the reference scenario (BAU) with the total discounted system-cost reductions realized in all DSM/EE scenarios. The level of cost-benefits increases as the level of DSM/EE measures increases. For example, if we implement 300 GWh per year DSM/EE measures within the state, end-users will save a total of more than 7 percent. Additional emissions reduction benefits are discussed in the next section.



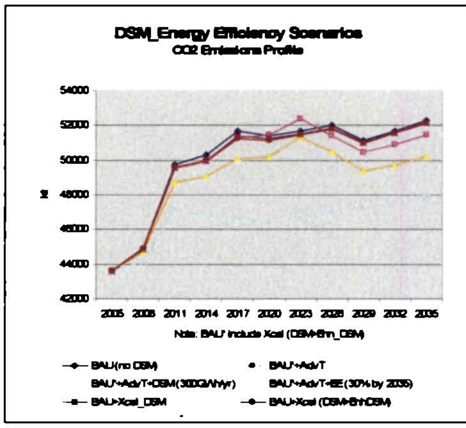
DSM/EE Scenarios	Cost Reduction from BAU	% Reduction from BAU
BAU (no DSM)	0	-
1- BAU+Xcel_DSM	-527	-1.03%
2- BAU+Xcel (DSM+EnhDSM)	-726	-1.41%
3- BAU°+AdvT	-1,290	-2.51%
4- BAU°+AdvT+DSM (300GWh/yr)	-3,817	-7.44%
5- BAU°+AdvT+EE (30% by 2035)	-9,890	-19.27%

Figure 35: DSM/EE Cost Benefits (2005M$)

Ratcheting up DSM/EE measures to 1% per year reduction in energy consumption would bring at least a 19 percent cost reduction from BAU's discounted total system cost, due in large part to avoided investment in new power plants and associated operating costs.

6.6.4 DSM/EE CO2 Emissions Profile

Over the course of the planning horizon, currently proposed DSM measures would have minimal impact on CO2 emissions. Combining both Xcel Energy's DSM measures and the Advanced Technology scenario, for instance, would reduce overall CO2 by 0.6%. By contrast, any of the aggressive DSM/EE scenarios would reduce CO2 emissions substantially. Reductions in CO2 emissions are a societal benefit that would be realized in addition to the cost savings described above. (Figure 36)



DSM/EE Scenarios	CO2 Reductions (kt)	% Reductions from BAU (no DSM)
BAU (no DSM)	0	
BAU+Xcel_DSM	-1,580	-0 3%
BAU+Xcel (DSM+EnhDSM)	-2,155	-0 4%
BAU*+AdvT	-3,315	-0 6%
BAU*+AdvT+DSM (300GWh/yr)	-13,150	-2.4%
BAU*+AdvT+EE (30% by 2035)	-39,238	-7 1%

Figure 36: DSM/EE CO2 Emissions Profile

6.7 Carbon Policy Scenarios

With rising awareness of greenhouse gases' potential impact on the environment, a number of legislative efforts are now under way to reduce C02 emissions. But while CO2 regulation has been roundly discussed, there is as yet no clear consensus on what will likely be accepted. What is likely is that within a few years the picture on CO2 regulation will become clearer than it is today.

As discussed in chapter 1, there is no federal requirement in the U.S. to reduce GHG, but states and local governments have begun to institute GHG reduction initiatives on their own. The Regional Greenhouse Gases Initiatives (RGGI) is one such program formed by the Northeastern states, and California recently passed the Global Warming Solutions Act of 2006, A.B. 32 to reduce carbon emissions from sources within the state. At the local level, many cities (such as the City of Denver) are establishing Climate Action Plans for their own GHG reduction programs [11].

To control GHG emissions from the Northeast's electric power sector, the RGGI has proposed a 'cap and trade' program similar to the one used to control acid rain. Each participating state has agreed to cap its GHG emissions from power production, setting the goal of stabilizing emissions by 2015 at the average level 2002-2004. The RGGI will then seek to reduce emissions by 10% by 2015, and by another 10% by 2020 [12].

6.7.1 Carbon Cap

Recently the United States' Senate introduced the Low Carbon Economy Act of 2007, S. 1766, which establishes a mandatory greenhouse gas (GHG) allowance program to maintain covered emissions at approximately 2006 levels in 2020, 1990 levels in 2030, and to cut emissions to at least 60 percent below 1990 levels by 2050.

The Colorado Climate Action Plan sets a goal for the state to achieve an economy-wide reduction in CO2 emissions by 20% below 2005 levels in 2020 and by 80% below 2005 levels in 2050. The plan calls for utilities statewide to reduce emissions and consumers to change the way they use energy. For example, the Action Plan calls for significant customer and government initiated reductions in energy usage including improvements in lighting performance, a call for industrial users' efficiency, and changes in building codes. To accomplish these goals, this study uses an aggressive energy efficiency scenario, which incorporates changes in usage driven by customers.[59]

To assess the impact of proposed climate action plans, we analyzed two scenarios: one to reduce the CO2 level by 10% and another by 20% by 2020. We also looked at ways to achieve 1990 levels by 2035 (Table 34). With the for 10% reduction goal, total net reduction of CO2 emissions over the planning horizon was 18.7 percent, while with a 20% reduction goal CO2 emissions were reduced 25.5, similar to the plan to achieve 1990 CO2 levels, which achieved a 25.1 percent emissions cut.

Table 34: Carbon Cap Policy Effective CO2 Reduction

Carbon Policy Scenarios	CO2 Reduction (kt)	% Reduction from BAU
BAU + 10% by 2020	102,437	18.7%
BAU + 20% by 2020	139,738	25.5%
BAU + 1990 Level	137,493	25.1%

The net system-wide additional cost to implement these carbon policies were mainly related to adding more renewables and efficient, less carbon intensive, new

[59] Colorado Climate Action Plan available online at : http://www.colorado.gov/energy/in/uploaded_pdf/ColoradoClimateActionPlan_001.pdf

generating capacity. Achieving a 10% reduction in CO2 emissions by 2020 cost roughly 10 percent more than implementing the BAU scenario, while the cost of achieving a 20% reduction was 15 percent higher, and or achieving 1990 emission levels 13 percent higher. (Table 35)

Table 35: Carbon Cap Policy Net Cost Increase from BAU (2005M$)

Carbon Scenarios	Cost Diff. From BAU	% Increase
BAU+10% by 2020	5,198	10.4%
BAU+20% by 2020	7,439	14.9%
BAU+1990 Level	6,712	13.4%

Figure 37 shows the electricity generation by fuel type for carbon policy scenarios compared to BAU.

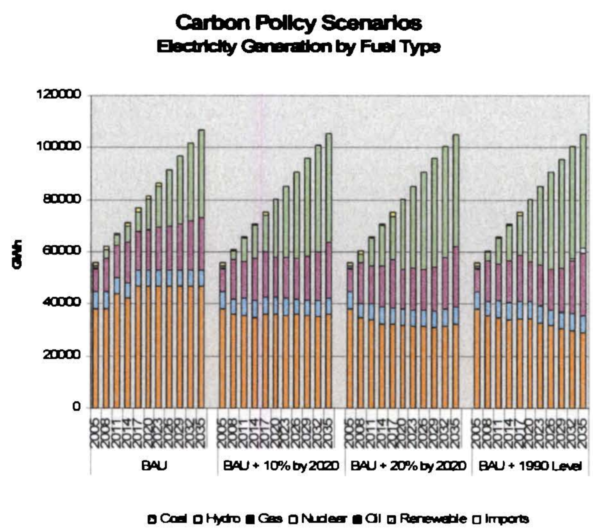


Figure 37: Carbon Cap Policy Electricity Generation by Fuel Type

As more stringent carbon policies are instituted, the level of coal-fired generation falls. With a 10% cap at 2005 levels, coal's share of total generation drops from over 40% to under 40% by 2020. With a 20% cap at 2005 levels, it falls to 30% by 2020, and with a cap based on achieving 1990 emissions levels, it falls to less than 30% by 2035. In the scenario where CO2 emissions reach 1990 levels by 2035, nuclear capacity becomes competitive with other generating technologies, in large part because it is second to renewables as a source of CO2-free generation. However, if restrictions on renewables (especially wind) are relaxed from 11 GW to higher levels in 2035, growth in nuclear capacity is delayed to future years.

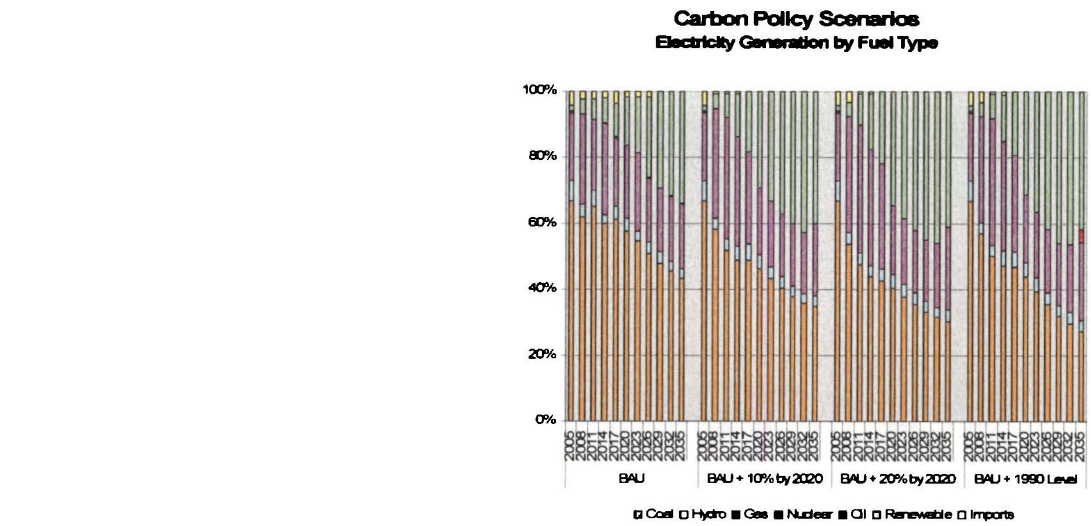


Figure 38: Carbon Cap Percent Share of Electricity Generation by Fuel Type

The portfolio of new capacity additions is also affected by different carbon cap scenarios. The more stringent the carbon cap policy, the less fossil-fueled generation technologies are used, and the more renewable technologies are added to the generation mix (Figure 39).

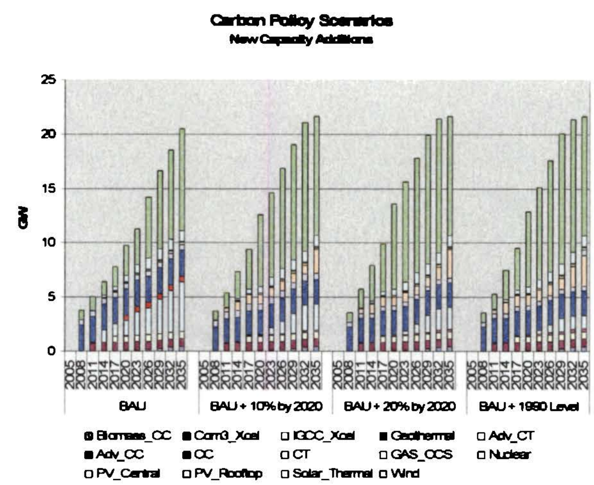
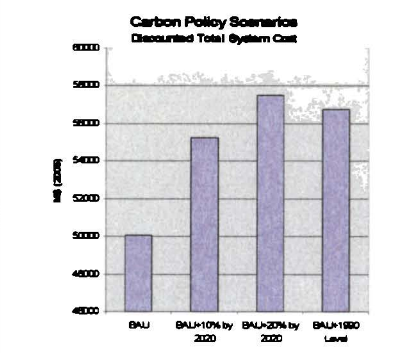


Figure 39: Carbon Cap Policy Scenarios New Capacity Additions

As stringent carbon cap scenarios require that even advanced CC and CT technologies be replaced, natural gas IGCC technology also enters the generation mix. In fact, the entrance of IGCC technology is a sign that renewable technologies

have reached their limits in meeting future carbon regulations alone. In this study wind technology's limit is set at 33% of total generation capacity mix in 2035, and that the limit for solar thermal generation is 1 GW in 2035. Wind integration and solar thermal site considerations therefore restrict the addition of renewables, even where they are the most cost effective choices. The next choice for less carbon intensive and cost effective technology appears to be natural gas IGCC technology with 90% carbon-capture sequestration.

When considering total discounted system costs and cost differentials for the three carbon cap policies, it appears that meeting the 2005-level cap (BAU+20%) by 2020 costs more than implementing the other two cap scenarios.



Carbon Scenarios	Cost Diff. From BAU	% Increase
BAU+10% by 2020	5,198	10.4%
BAU+20% by 2020	7,439	14.9%
BAU+1990 Level	6,712	13.4%

Figure 40: Carbon Cap Policy System Costs and Differentials

It is also estimated that meeting the 1990-level cap by 2020 will cost the system about l.5% less than meeting the 20% cap by 2020(Figure 40).

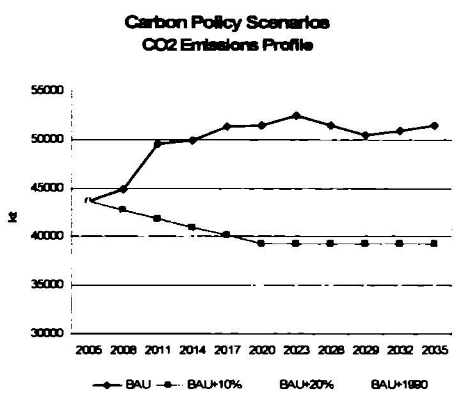
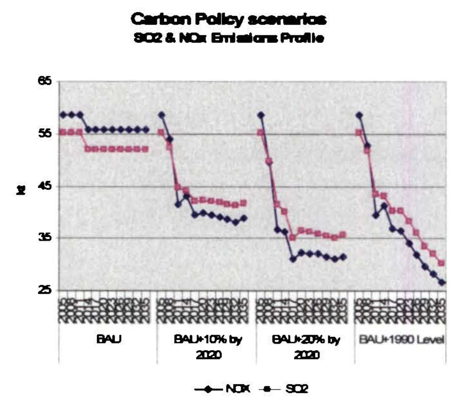


Figure 41: Carbon Cap Policy CO2 Emissions Profile

When considering the CO2 emissions profile of the three carbon cap policies, it should be noted that implementing a 1990 cap by 2035 would allow for more gradual investment in less carbon-intensive technologies, resulting in a less discounted total system cost over the planning horizon (Figure 41).

6.7.2 Co-Benefit of Carbon Cap

Another important benefit of instituting a carbon policy is reduction of such criteria pollutants as SO2 and NOx emissions. As shown in Figure 42, the emission profile for both SO2 and NOx reduces in 2011as carbon policies take effect. This is a co-benefit of emission policies designed to control other pollutants and entails no additional cost. A beneficial byproduct of constraining fossil-fueled generation is a drop in NOx emissions of 30-52% and of SO2 emissions of 20-42% percent.



Scenarios	NOX	SO2
10% Cap	30.2%	19.6%
20% Cap	43.6%	31.5%
1990 Cap	52.3%	41.9%

Figure 42: SO2 and NOx Emissions Profile

6.7.3 Carbon Tax

We devised two scenarios to assess the impact of two possible carbon tax policies. One is a Btu tax applied upstream based on the heat content of fossil fuel production. The other is a tax applied downstream based on CO2 output from the use of fossil fuels.

Btu Tax: This is an energy tax based on heat content –the British Thermal Units (Btu) – generated by particular fuels. As introduced in the United States in the1990s, the Btu tax would have been imposed on electricity generation by coal, natural gas, petroleum products, and imported electricity at a base rate of 25.7 cents per million Btus (p/MBtu).[60] The tax would have had a neutral impact on a regional basis and would have affected the market shares of energy sources equally. In the event, the Btu tax met with strong opposition in the United States and was never adopted.

[60] The proposed Btu tax by the Clinton Administration would have applied to nuclear-generated electricity or hydro- electricity if adopted. We did not apply Btu tax to nuclear or hydro electricity in this study.

In our Btu tax scenario, we applied a tax of 50 cents (p/MBtu) upstream (double what was proposed in the 1990s) to all fossil fuels used to generate electricity. Figure 43 shows the CO2 emissions profile following imposition of such a Btu tax. It should be noted that, over the planning horizon this Btu tax would increase the discounted total system cost by more than 8% while reducing total CO2 emissions by less than 1%. This is mainly due to the fact that the Btu tax has a neutral impact on the system and affects all fossil fuel costs and CO2 emissions proportionally.

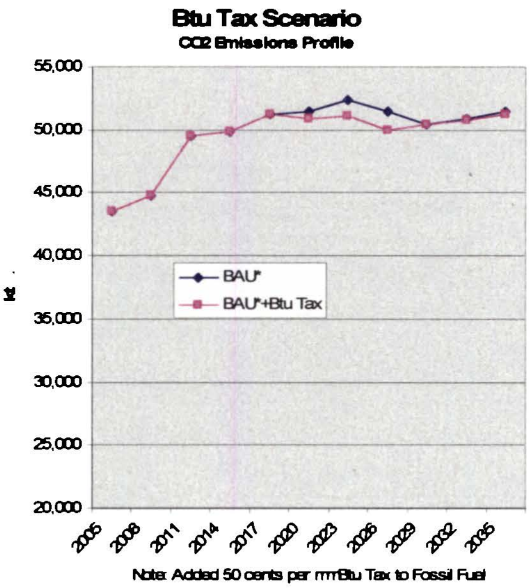


Figure 43: Btu Tax CO2 Emissions Profile

CO2 Tax: Another tax proposal is a CO2 tax that would impose a specific dollar amount per metric tonne of CO2. This tax is based on the amount of CO2 emitted and would apply to electricity generated by fossil fuels (coal, natural gas, petroleum products, and imported electricity).

Evaluating how a CO2 tax of $20-$70 per tonne downstream would affect total system CO2 reduction, we noted that although large tax revenues were generated, the tax did little to shift fuel usage.[61] Once constraints on renewables were relaxed, however, the system reacted to a $58/t tax by building more wind power plants and retiring old coal-fired generating units.

[61] We did not model carbon capture and sequestration (CCS) retrofits option for cost comparison on the existing coal-fired power plants. This option is a viable option once CCS retrofit technology is developed

Figure 44 shows the level of electricity generation by fuel type associated with four different sizes of CO_2 tax. As CO_2 tax rises above $50/t, the system begins to reduce its use of coal. Coal, the most carbon-intensive fuel, begins to be replaced with renewables, particularly wind generation, and imported electricity levels also diminish as CO_2 taxes increase.

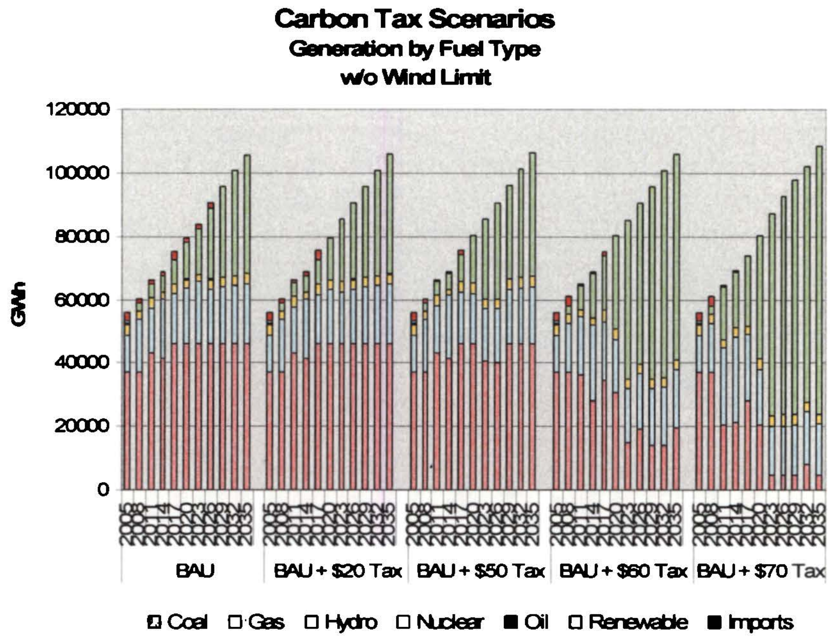


Figure 44: CO2 Tax Scenario Generation by Fuel Type

Once a CO_2 tax is imposed and constraints on renewables are relaxed, fuel types and new capacity additions begin to shift within the system (Figure 45). At $20/t CO_2 tax, the system reacts neutrally and no major shift in new capacity additions take place. At $50/t CO_2 tax, the system reacts minimally to replace new fossil-fueled capacity (e.g., CTs) with renewables. At $60/t CO_2 tax and higher, the system shifts dramatically toward more renewables and reduced fossil-fueled new capacity. It should be noted, however, that the relationship between renewable and fossil-fueled capacity is not one-to-one. Because it takes more new wind capacity to replace every unit of fossil-fueled capacity lost (due to lower capacity credit assigned to wind). The impact of integrating large new wind capacity into the system, moreover, has yet to be evaluated. Other options – such as energy efficiency measures and retrofitting existing coal-fired generating units with carbon capture and sequestration technology – also need to be considered.

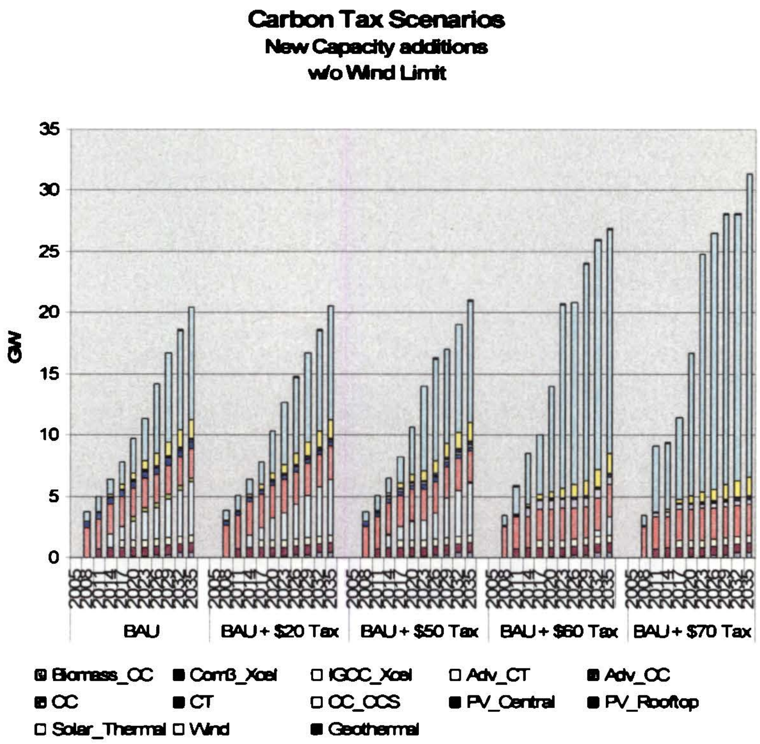


Figure 45: CO2 Tax Scenario New Capacity Additions

Different levels of tax on CO2 produce very different effects on the discounted total system cost, amount of tax revenues, and CO2 reductions. When the CO2 tax is set at or below $50/t, the system reacts minimally to reduce CO2 emissions. Although the tax generates over $21 billion over the planning horizon, the system will invests only 1.5% more to achieve 4% reduction in CO2. As the CO2 tax is increased to >$50/t, however, the system invests proportionally more on renewables, resulting in 17% higher costs and a 40% reduction in CO2 emissions.

Table 36: CO2 Tax Costs and Tax Revenues

Carbon Tax Scenarios	Discounted Total System Cost	% Cost Diff. from BAU	CO2 Tax Revenue (2005M$)	Diff. from BAU (cost+Tax)	CO2 Reduction (kt)	CO2 % Reduction	Avoided CO2 Cost ($/t)
BAU	50,007	-	-	-	-	-	-
BAU+$20	50,057	0.1%	8,874	17.8%	-6,468	-1.2%	-1,380
BAU+$50	50,759	1.5%	21,410	44.3%	-24,286	-4.4%	-913
BAU+$60	58,683	17.3%	17,253	51.8%	-206,625	-39.6%	-125
BAU+$70	64,047	28.1%	14,334	56.7%	-294,173	-53.9%	-96

Under this scenario, any reductions in tax revenues come about because consumption of fossil fuel has been reduced by the introduction of renewables. With a CO2 tax of $70/t, undiscounted tax revenues from CO2-emissions decline sharply

beginning in 2017, when more renewables are online to displace fossil-fueled generation (Table 36 and Figure 46).

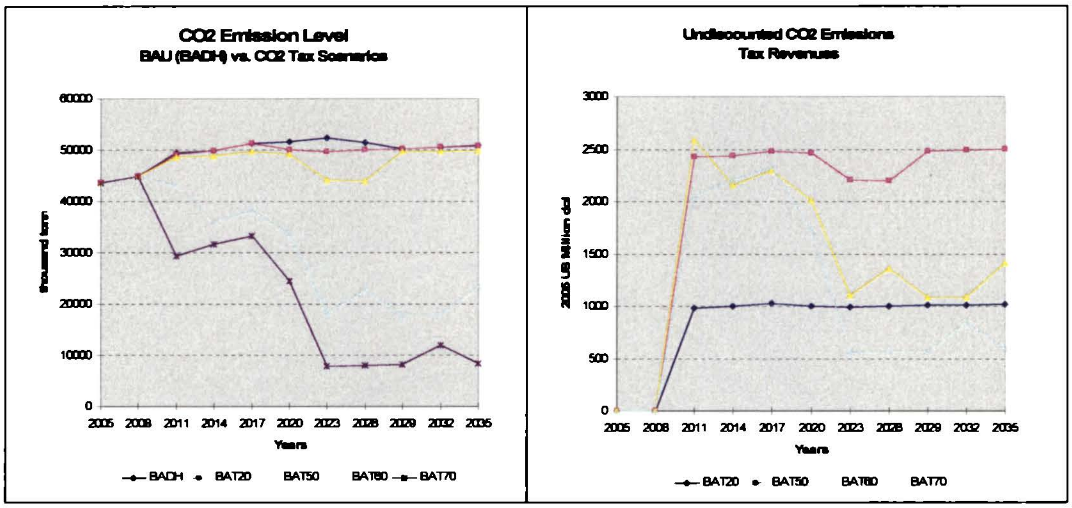


Figure 46: CO2 Tax Scenario CO2 Emissions and Tax Revenues Profile

The emissions profile for the criteria pollutants SO2 and NOx mirrors that for CO2 emissions from coal-fired power plants (Figure 47).

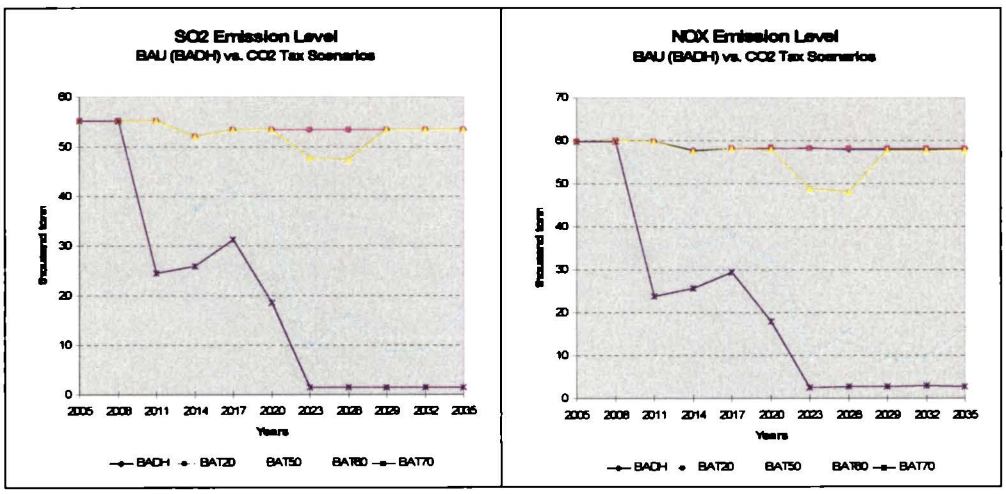


Figure 47: CO2 Tax Scenario Criteria Pollutant Profile

6.7.4 Biomass Co-Fire

In this study, biomass was modeled first in a stand-alone biomass gasification combined cycle and then considered as a co-firing option, with all bituminous coal-fired units in Colorado posited at a ratio of 10% biomass to 90% coal. Clearly, the

competitiveness of biomass-generation technologies depends heavily on the price and availability of biomass fuel resources. For biomass generation to become a major player in the RPS, the prices for biomass feedstock need to be competitive with coal price, which is at near or under $2.00 per million Btu (mmBtu). In this study, the DOE average price of $2.25/mmBTu was escalated over the planning horizon to reflect an inflation rate of 1.5%.

In Colorado, when biomass is co-fired with all bituminous coal-fired units at the ratio of 10 percent biomass to 90 percent coal, the total reduction in CO_2 emissions is estimated to be around 1.1%. Over the planning horizon, this amounts to 6,000 kt but increases the discounted total system cost by $2.2 billion, and a cost for CO_2 reduction of roughly $370/t. To make biomass co-firing a viable option for CO_2 reduction, prices for biomass feedstock must be competitive with coal (Figure 48)

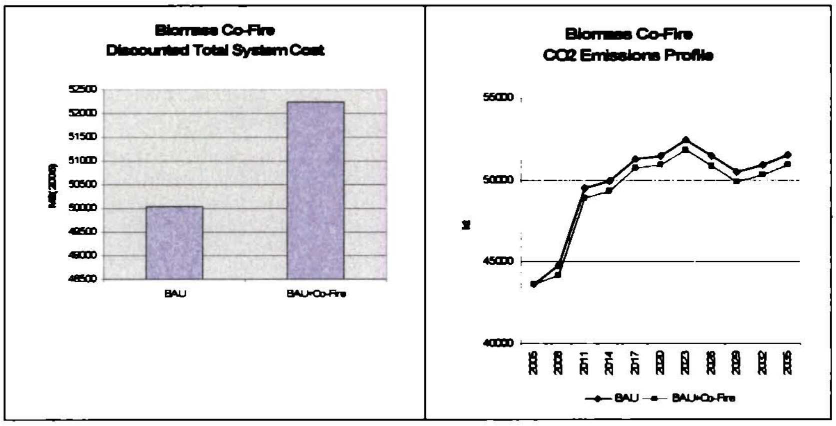


Figure 48: Biomass Co-Fire Cost and CO_2 Emission Profile

6.8 Sensitivity Analysis

'Sensitivity analysis' generally means variations in output following changes in a model's inputs. In evaluating sensitivities within the Colorado model, we considered both single (parametric) and multiple (global) variables. Single variable sensitivity analysis is used to evaluate the response to changes in a single input (such as the cost of natural gas) while holding all other inputs constant. Multiple variable sensitivity analysis is used to evaluate the relationship of multiple inputs and outputs [29]. Analyzing multiple variable sensitivities involves the perturbation of multiple model inputs simultaneously and the evaluation the effects of each input, singly and together, on model outputs. Within the Monte Carlo simulation, input perturbation is determined by a random number generator [60].

The Monte Carlo simulation is a statistical sampling technique used to obtain a probabilistic approximation of the solution for a particular model. The goal of a Monte Carlo simulation is to identify key sources of variability and uncertainty and to

quantify the relative contribution of these sources to the overall variance and range of model results. Researchers and analysts most often use the Monte Carlo simulation to evaluate the expected impact of risk (the probability of an undesirable outcome) and policy changes involved in decision making [61].

6.8.1 Gas Prices Sensitivity Analysis

There are large variations in projecting the natural gas prices. Utilities use various sources of data to compile data and develop projections for fuel prices. In making projections for the price of natural gas, for example, Colorado's Xcel Energy used a blend of data from the New York Mercantile Exchange, EIA, and other sources. Figure 14 compared gas price projections by the EIA and by Xcel. Since Xcel's higher forecast is generally considered more representatives of actual fuel market prices in the West, it was adopted as the basis for the Colorado model.

For sensitivity analysis with regard to the effect of gas prices on variations in fuel consumption and new capacity additions, we inflated the Xcel natural gas price by 50% (Semi-High gas price scenario) and then by 100%.(high gas price scenario) as input into the model.

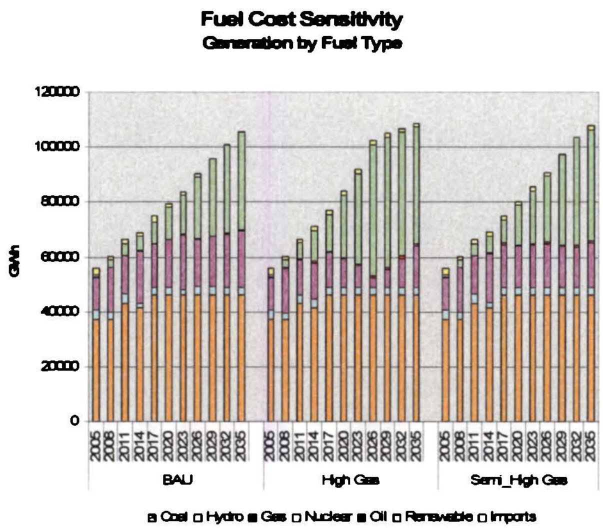


Figure 49: Natural Gas Sensitivity Generation by Fuel

As natural gas prices increase and coal-fired, hydro units and imports reach maximum levels, renewables are brought in to fill the gap created by displaced natural gas generation (Figure 49).

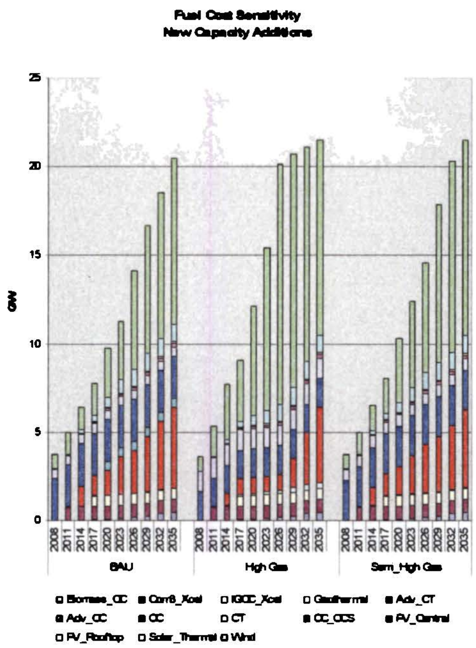
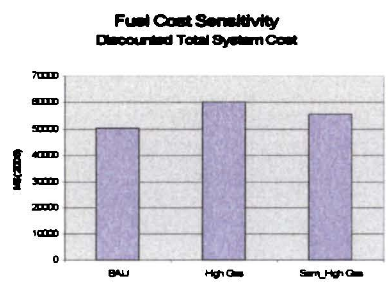


Figure 50: Fuel Cost Sensitivity New Capacity Additions

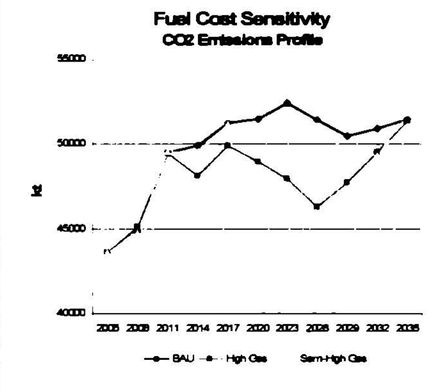
As was noted before, the renewable electricity generation in the model is constrained at 33% of total generation in 2035; forces the system to begin investing in more renewable generation resources in earlier years for higher renewable generation after all coal-based import limits are exhausted. In the high gas scenario, for example, all imports limits are reached in all periods and the system begins investing in more renewables as early as 2011 to compensate for reduced investment in advanced CTs (Figure 50). In the semi-high gas price scenario, the total discounted system costs increase by 10%, and in the high gas price scenario, they increase by 20% (Figure 51).



Gas Sensitivity	Cost Increase	% Increase
High Gas	10,093	20.2%
Semi_High Gas	5,538	10.0%

Figure 51: Fuel Cost Sensitivity Total System Cost Comparison

In the high gas cost scenario, CO2 emissions drop over the planning horizon by as much as 3.5%, while in the semi-high gas cost scenario, they drop by less than 1%. Higher gas prices have minimal impact on CO2 emissions because most natural gas-fired units (CTs) operate with low capacity factor throughout the year, coming online to meet system peak demand only. In addition, carbon intensity is much lower in high efficiency gas units than in fossil-fueled generating units and carry a much smaller carbon footprint. (Figure 52)



Gas Sensitivity	CO2 Reduction (kt)	% Reduction from BAU	CO2 Avoided Cost ($/t)
High Gas	-19,302	-3.5%	-523
Semi-High Gas	-4,769	-0.9%	-1,161

Figure 52: Fuel Cost Sensitivity CO2 Emissions Profile

6.8.2 Load Forecast Sensitivity Analysis

Energy planning models require forecasts of energy demand for all the years in the planning horizon. To alleviate the uncertainties necessarily involved in projecting energy demand over the long term, we devised a low and a high energy needs projection for the sensitivity analysis. The low energy projection resulted in an average annual growth rate of 1.5%, while the high projection forecast an average annual growth rate of 2.9%. (Figure 53)

In the event, Colorado's economy and population have grown faster than expected and energy consumption and end-user demand have grown along with it. With renewables capped at 33% of total generation in 2035, the state needs to build more fossil-fueled power plants to meet demand increases. In a slow-growing economy, or where less energy is used due to conservation or high electricity prices, demand for energy demand decreases and the state will need to build fewer power plants, including renewables, to meet end-user needs. (Figure 49)

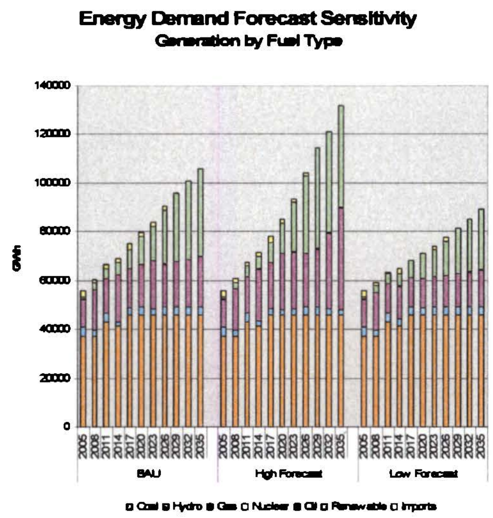
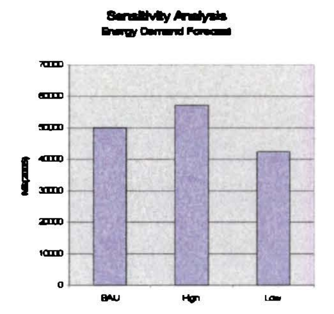


Figure 53: Load Forecast Sensitivity Generation by Fuel Type

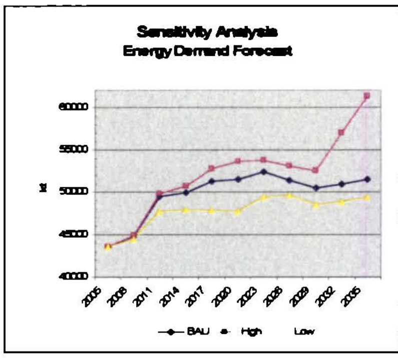
The power generation system's sensitivity to load will be a major factor determining future costs and benefits. In the high load forecast, the system incurs more than 14% in discounted total system costs. The opposite is true where the load forecast is lower than BAU, and the system's discounted total costs are reduced by more than 15% (Figure 54).



Forecast Sensitivity	System Cost Increase (2005M$)	% Increase from BAU
High	7,103	14.2%
Low	-7,689	-15.4%

Figure 54: Load Forecast Sensitivity System Cost Comparison

With regard to its CO2 emissions profile, Colorado follows the expected pattern. A higher load forecast increases the CO2 emissions profile by more than 4%, while a low load forecast decreases the system's CO2 emissions profile by more than 4%. (Figure 55)



Forecast Sensitivity	System CO2 Impact (kt)	% Increase from BAU
High	25,936	4.7%
Low	-22,293	-4.1%

Figure 55: Energy Demand Forecast Sensitivity CO2 Emissions Profile

6.8.3 Sensitivity Analysis using Monte Carlo Simulations

In this study, the Monte Carlo simulation is used to generate random outcomes for each probabilistic variable according to its probability of distribution [62]. When repeated enough (in this case, a thousand times) this process creates a distribution of results. Major outputs of the model selected for sensitivity analysis using Monte Carlo simulations include:

- the existing installed capacity use
- new generation technology levels
- fuel usage
- marginal cost of generation
- total system cost.

In the Monte Carlo simulation, uniform probability distribution was used for each of the inputs assumed to be independent of each other [29]. In the high gas scenario, natural gas prices were allowed to range from -10% to +100% of their values. The generation technology-specific discount rate (or hurdle rate) was allowed to range between 7.5% (system discount rate) and 18%.

To represent the current status and future advancement of various renewable technologies, a renewable technology growth rate variable was also selected. Mature technologies (such as wind) were represented at 20% growth rate, whereas less mature generation methods (such as solar thermal and solar PV) were represented at 10% and 30% growth rate, respectively. (Table 37)

Table 37: Monte Carlo Simulation Inputs

Model Inputs	Units	Input Range			Description
		Default	Low	High	
Natural Gas Cost	$M/PJ	0	-1.2	24	Natural Gas Price increases
New Generation Technology Discount Rate	-	0.075	0.075	0.2	Technology-Specific hurdle rate
Renewable Growth Rate					Growth rate of renewables
Wind	% growth	20	0	30	
Solar-PV	% growth	30	0	30	
Solar Thermal	% growth	10	0	20	
Biomass	% growth	15	0	20	
CapacityLimit					Peak capacity for technology
Wind	Gigawatts	0.835	0	11	
Solar PV	Gigawatts	0.03	0	0.5	PV-Rooftop at 0.250
Solar Thermal	Gigawatts	0.025	0	1	
Geothermal	Gigawatts	0	0	0.07	
Biomass	Gigawatts	0	0	0.44	

The fuels tracked in this simulation included coal, natural gas, and oil. The types of renewable technologies included biomass, geothermal, solar, and wind power. Other inputs included: forecasts of natural gas cost, restraints on growth bounds of renewable technologies; and technology-specific hurdle rates. Figure 56 shows the mathematical representation of an electrical system cost optimization, as objective function, formulated in the Monte Carlo simulation [63].

Simulation Model

Xjv - Capcity
Cjv - Capacity Cost

Yjv - Electric output
Fjv - Fuel cost

Q - Energy demand
min.
Total Cost = (Fjv * Yjv + VAROM) + (Cjv * Xjv + FXDOM)

s.t.,
0<Y<=X & AF(X)>=0
Y>=Q

Figure 56: Mathematical Representation of System Objective Function

6.8.4 Uncertainty of Model's Input/Output

Uncertainty in a forecast arises from the combined uncertainties of all its assumptions and the way these are weighted in the formulas used in the model. An assumption might have a high degree of uncertainty, for instance, yet have little effect on the forecast because it is not weighted heavily in the model formulas. On the other hand, an assumption with a relatively low degree of uncertainty might influence a forecast greatly. Sensitivity refers to the amount of uncertainty in a forecast that is caused by the uncertainty of an assumption as well as by the model itself [60].

Figure 57 shows the model's sensitivities measured against total costs by rank correlation coefficients. Positive coefficients indicate that an increase in the

assumption is associated with an increase in the forecast. Negative coefficients imply the reverse. In this case, natural gas prices have a positive coefficient, or very strong correlation, with total costs. By contrast, wind growth rate has a negative coefficient, meaning that increased amounts of wind generation capacity in the system will result in less total cost.

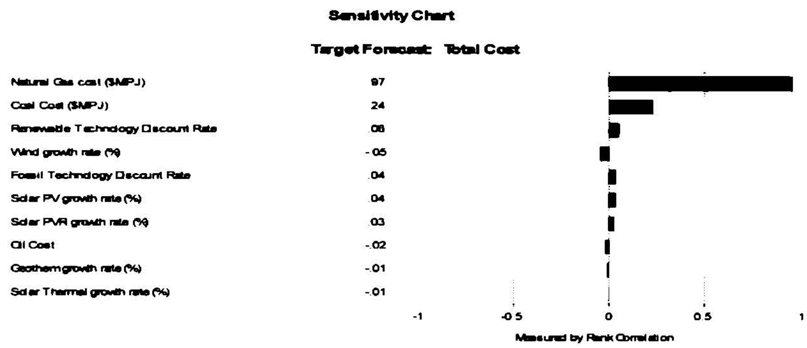


Figure 57: Sensitivity Chart of Target Forecast – Total System Cost (2035)

6.9 Elastic Demand

Elastic demand modeling allows us to obtain partial equilibrium between supply and demand in a region's energy system. Partial equilibrium represents the situation in which consumer and producer surplus are maximized. The total surplus of an economy is the sum of the suppliers' and the consumers' surpluses. In MARKAL, the term 'supplier' means any economic agent that produces (and sells) one or more commodities (e.g., an emission permit, an energy service). A 'consumer' is a buyer of one or more commodities. Some agents may be both suppliers and consumers, but not for the same commodity. The Reference Energy System for a given commodity defines a set of suppliers and a set of consumers.

Generally, the set of suppliers of a commodity are represented by their inverse production function, where the marginal production cost of the commodity (vertical axis) is plotted as a function of the quantity supplied (horizontal axis). In MARKAL, the supply curve of a commodity is not explicitly expressed as a function of factor inputs (such as aggregate capital, labor, and energy in typical production functions used in the economic literature), It is rather represented as the inverse step-wise constant and increasing supply function of each factor. This is because in Linear Programming, the shadow price of a constraint remains constant over a certain interval and then changes abruptly, giving rise to a stepwise constant functional shape.

Each horizontal step of the inverse supply function indicates that the commodity is produced by a certain technology or set of technologies in a strictly linear fashion. As

the quantity produced increases, one or more resources in the mix (either a technological potential or some resource's availability) is exhausted. At this point, the system must start using a different (generally more expensive) technology or set of technologies and will produce additional units of the commodity only at higher unit cost.

Each change in production mix therefore generates one step of the staircase production function with a value-inverse demand function, which is a step-wise constant, decreasing function of the quantity demanded. As shown in Figure 58 the supply-demand equilibrium is at the intersection of the two functions, and corresponds to an equilibrium quantity Q(e) and an equilibrium price P(e), which means that at this price, suppliers are willing to supply the quantity Q and consumers are willing to buy exactly the same quantity Q.

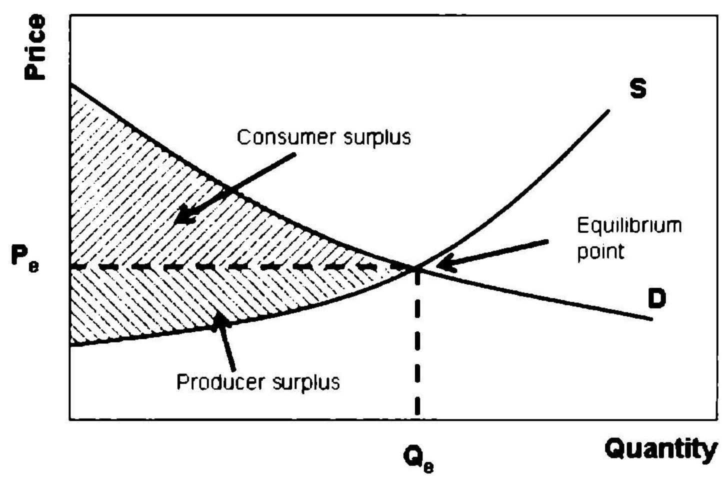


Figure 58: Price/Demand Trade-Off Curve

The concept of total surplus maximization extends the cost minimization approach upon which bottom-up energy system models are based. These types of models have fixed energy service demands, and are therefore content to minimize the cost of supplying these demands. In contrast, the MARKAL demands for energy services are themselves elastic to their own prices, allowing the model to compute the supply-demand equilibrium.

Each energy service within the MARKAL model has several attributes that describe (a) the amounts of service to be satisfied at each time period, (b) the seasonal/time-of-day nature of these electricity requirements, and (c) the price-elasticity of the demand and the allowed interval of demand variation. In policy runs, the mix of inputs required to produce one unit of a sector's output is allowed to vary according to defined elasticities of substitution.

MARKAL is a technology-explicit, partial equilibrium model that assumes price-elastic demands and competitive markets with perfect foresight (resulting in marginal-value pricing). In MARKAL, the surplus function is derived from the demand and supply functions that link prices and quantities for different economic agents. The equivalence programming of the MARKAL-ED (elastic demand) is based on the following considerations:[62]

- *Aggregate demand curve.* On the aggregate demand curve, the price corresponding to a given quantity represents the willingness to pay to get one more unit of the product. It reflects the value of the product to the consumer given the available quantity.

- *The supply curve.* The supply curve represents the long-run marginal production cost of a firm with the total cost of producing the output being minimized. It gives the minimum price at which suppliers are willing to supply the quantity.

- *Maximum net benefit.* The maximum net benefit is obtained when the marginal unit is just beneficial, that is, when the marginal production cost and the price (the value for the consumer) are equal.

In MARKAL-ED the surplus function is linearized to obtain a linear formulation of the non-linear objective function for the LP (Linear Programming) solver.

6.9.1 Elastic Demand Fuel Consumptions

Figure 59 compares total system fuel consumptions under various scenarios for both standard and elastic demand conditions. Under the standard condition, most of the evaluated scenarios show the same level of fuel consumption except for the high load forecast and Aggressive DSM/EE scenarios. The high load forecast establishes the upper boundary and the Aggressive EE scenario the lower boundary of total system fuel consumption, while the DSM and low-load forecast scenarios fall in between but have lower consumption lower than in the BAU scenario.

Under the elastic demand condition, all but the high load and Aggressive EE scenarios fall under the BAU level of fuel consumption. This exercise shows that under the elastic demand condition, the system responds to long-run marginal production costs and adjusts system demand to maximize producer/consumer surpluses, which results in an optimized level of fuel consumptions and lower emissions and costs.

[62] MARKAL users' manual.

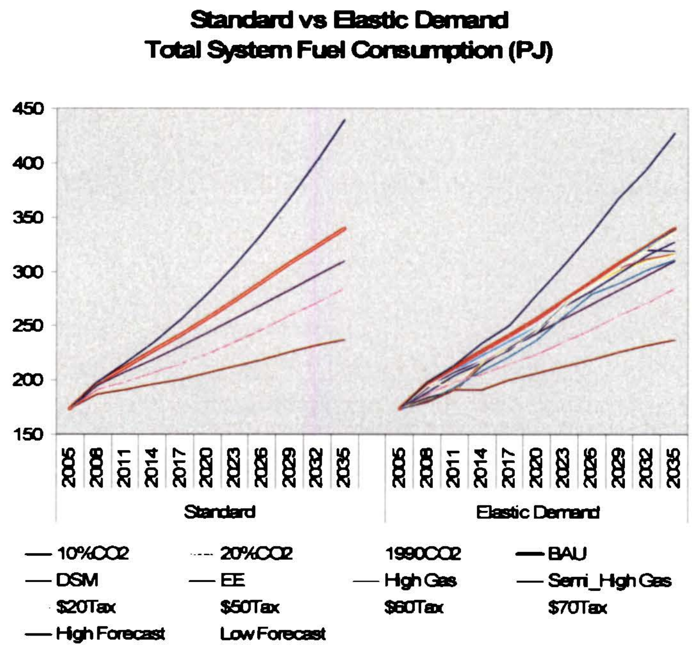


Figure 59: Total System Fuel Consumption under Standard and Elastic Demand

Table 38 shows the elastic demand adjustments to areas under the consumer/producer curves of modeled scenarios to arrive at total surplus maximization and cost minimization.

Table 38: Elastic Demand Consumer/Producers Surpluses

Elastic Demand Surpluses	
Consumer/Producer Surplus	2005M$
Scenarios	
BAU	0
Carbon Policy	
10% below 2005 by 2020	-4,539
20% below 2005 by 2020	-6,370
1990 level by 2035	-5,882
DSM/EE Prgrams	
DSM (300 GWh/yr)	2,524
EE (1% per year)	8,640
Fuel Cost Sensitivity	
High Gas	-8,856
Semi-High Gas	-5,119
Forecast Sensitivity	
High Energy Forecast	-6,888
Low Energy Forecast	7,681

Figure 60 shows the CO2 emissions profile for 13 scenarios compared to BAU for both standard and elastic demand. In high load scenarios show the highest CO2 emissions (Figure 60). The lowest CO2 emission profile was the $70/t CO2 tax scenario, followed by the $60/t, 20% cap, the1990-level cap, and 10% cap on CO2 emissions. (It should be noted that emission profiles under elastic demand conditions are slightly lower and more uniformly distributed, since fuel consumptions were optimized to account for demand elasticity in response to long-run marginal costs.)

It should also be noted that the sharp decline in CO2 emissions under the CO2 tax of $60/t and $70/t was due to the accompanying sharp decline in use of existing coal-fired power plants, which, with no use limits, were replaced with higher penetration of renewables – in particular wind technology. As noted before, wind use for all scenarios (except the CO2 tax scenario) was constrained at 33% of total generation

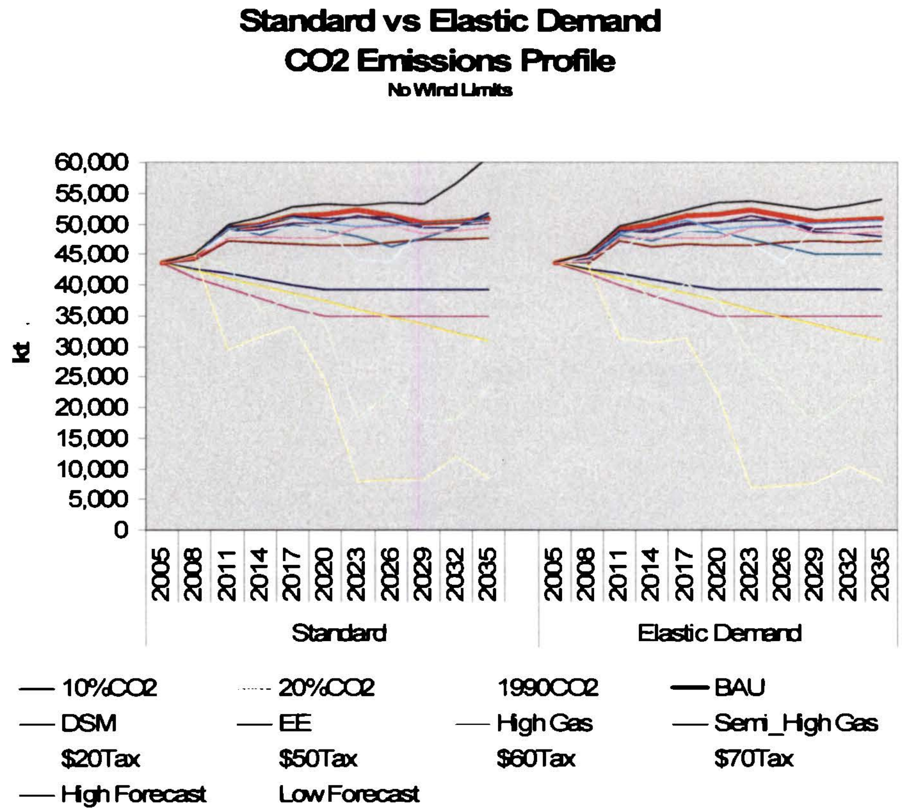


Figure 60: CO2 Emissions Profile under Standard and Elastic Demand

6.10 Scenario Comparison and Conclusion

For this study, five main types of scenario were developed, and analyzed:

- Reference Scenario (Business-as-Usual)
- Advanced Emerging Technology Scenario
- DSM/Energy Efficiency Scenario, and
- Regulatory Policy Scenarios, and
- Sensitivity Scenarios

The study focused on Colorado's electric power system and supply-side energy system incorporating Renewable Portfolio Standards, Demand-Side Management strategies, and Energy Efficiency measures. The work aims to demonstrate the current status of the state's power sector and to quantify pathways for achieving sustainable energy production in the future.

Within the five main types of scenario, a total of 17 scenarios were modeled and analyzed (including sensitivity scenarios), covering the period from 2005 to 2035. The Reference Scenario (Business-as-Usual) represented the most probable development of the power system under present known conditions. The other scenarios served mainly to show possible ways toward the sustainable development of a power system that incorporates clean energy technologies and mitigate GHG emissions.

In all scenarios, attempts to mitigate CO2 emissions impose considerable costs except energy efficiency and DSM measures (Figure 61). While energy efficiency and DSM measures represent the most promising pathways for reducing discounted total system costs and at the same time reducing CO2 emissions. However, using these methods, projections of CO2 levels in the future will never meet any of CO2 cap requirements. With DSM and energy efficiency measures, total net reductions in CO2 by 2035 will range between 0.3-7percent. The system cost reduction is the most promising between 1-19 percent over the 30 years planning horizon.

Although they cost more than BAU, both the carbon cap policy scenario and carbon tax policy scenario modeled were able to reduce CO2 emissions to expected levels by 2020 or 2035. In the two scenarios analyzed, one reduces CO2 emissions by 10% and the other by 20% by 2020. The net impact of the 10% reduction s a 19 percent reduction in CO2 at 10 percent higher cost, while in the 20% policy scenario, the net impact is a 25.5 percent reduction in CO2 emissions at 15 percent higher cost.

Analyses of carbon tax policy showed that, when renewable resources are constrained, where wind power, for example, s bounded at 11 GW and Solar Thermal at 1 GW by 2035, carbon taxes at various level did not respond to taxes. We examined four carbon tax levels ($20, $30, $40, and $50 per ton) and found the system minimally reactive to taxes. According to the model, huge tax revenues were

generated with virtually no impact on carbon-intensive electricity generation. By contrast, when bounds on renewable were relaxed and carbon taxes slightly raised, the system quickly reacted to slow generation from carbon-intensive generating facilities. The system showed sensitivity to a carbon tax of $58 per ton, when coal-based generation began to be phased out in favor of adding renewable (wind) capacity.

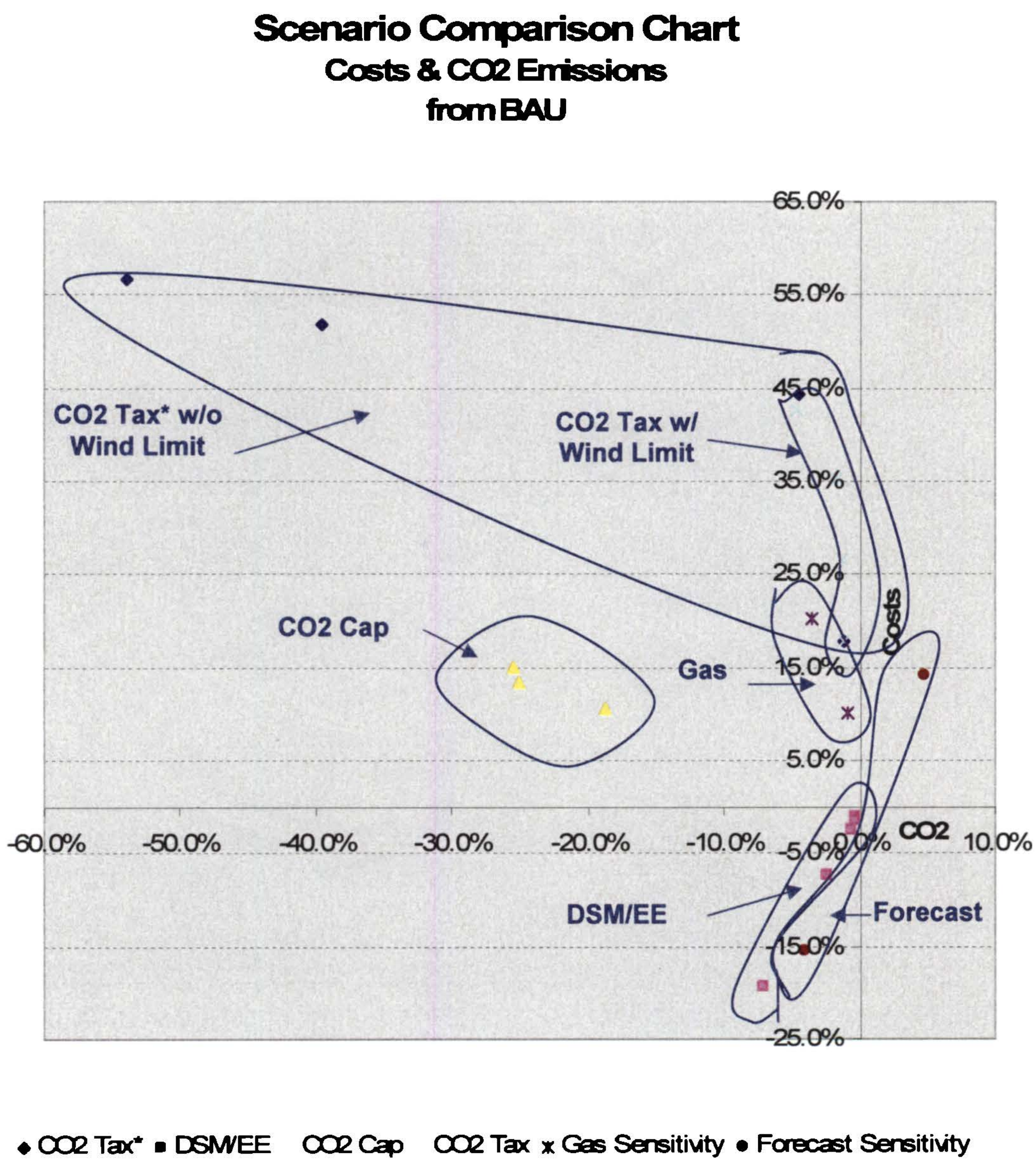


Figure 61: Scenario Comparison Chart – Costs & CO2 Emission Differential from BAU

Sensitivity analyses had both positive and negative effects on the system. Gas price sensitivity reduced the CO2 emission profile but increased net system costs. Load forecast sensitivity analysis showed a direct relation between CO2 emissions, cost, and energy demand, with low forecasted demand leading to reducedCO2 emissions and system costs and high forecasted demand leading to increases in both CO2 emissions and costs.

This study provides a foundation for policymakers to assess the implications of strategies designed to mitigate carbon dioxide emitted by Colorado's power sector and to identify policies that will provide sustainable energy at a reasonable cost in the future. It uses an optimization model to evaluate different energy production mixes and the costs and benefits of different policy options. The study makes a substantial contribution to the development of state power system geared not only to meet future energy needs and keep down costs but also to make the best possible use of policies and clean energy technologies to mitigate the emission of pollutants and greenhouse gases.

6.11 Future Research Work

One of the most important criteria of using MARKAL model for this study is that it's expandable to other sectors of economy. One logical addition to this model is to develop and disaggregate the sectoral demand into more refined demand devices such as space cooling, space heating, or office buildings or appliances. Another most import remaining work is to add the transportation sector followed by mining and oil and gas industry to quantify their level of upstream greenhouse gas emissions. Together, the model can provide a statewide energy system model and can be used as policy research toll to assess climate change and greenhouse gas initiatives.

APPENDIX A: MODEL INPUT FOR BASE-YEAR (2005) POWER PLANTS CAPACITY AND HEAT RATE

List of Colorado Installed Capacity - Base-Year (2005)

Technology Type	Plant Name	Owner	Capacity (MW)	Type	Fuel Type	Heat Rate (mmBTu/MWh)
Fossil Fuel	Cameo_1	PSCo	24	ST-Coal	Bit	12.764
	Cameo_2	PSCo	54	ST-Coal	Bit	10.994
	Nucla_1-4	TSGT	100	ST-Coal	Bit	11.827
	Hayden_1	PSCo	205	ST-Coal	Bit	10.357
	Hayden_2	PSCo	300	ST-Coal	Bit	12.246
	Cherokee_1	PSCo	115	ST-Coal	Bit	10.807
	Cherokee_2	PSCo	120	ST-Coal	Bit	10.470
	Cherokee_3	PSCo	165	ST-Coal	Bit	10.145
	Cherokee_4	PSCo	388	ST-Coal	Bit	9.532
	Valmont_5	PSCo	199	ST-Coal	Bit	9.391
	W N Clark_1	WPE	19	ST-Coal	Bit	13.056
	W N Clark_2	WPE	24	ST-Coal	Bit	13.056
	Trigen Colorado	IPP	20	ST-Coal	Bit	10.864
			1733			**10.62**
	Martin_Drake_5	CSU	47	ST-Coal	Sub_Bit	11.678
	Martin_Drake_6	CSU	79	ST-Coal	Sub_Bit	11.182
	Martin_Drake_7	CSU	133	ST-Coal	Sub_Bit	10.427
	Nixon_1	CSU	208	ST-Coal	Sub_Bit	10.492
	Pawnee	PSCo	505	ST-Coal	Sub_Bit	10.430
	Craig_1	TSGT	428	ST-Coal	Sub_Bit	10.307
	Craig_2	TSGT	428	ST-Coal	Sub_Bit	10.423
	Craig_3	TSGT	408	ST-Coal	Sub_Bit	10.155
	Rawhide	PRPA	270	ST-Coal	Sub_Bit	10.415
	Arapahoe_3	PSCo	47	ST-Coal	Sub_Bit	11.808
	Arapahoe_4	PSCo	121	ST-Coal	Sub_Bit	11.251
	Comanche_1	PSCo	366	ST-Coal	Sub_Bit	10.453
	Comanche_2	PSCo	370	ST-Coal	Sub_Bit	10.470
			3410			**10.47**
	Zuni_1	PSCo	39	ST-NGA	NGA	13.387
	Zuni_2	PSCo	68	ST-NGA	NGA	13.387
			107			**13.39**
	Ft_St_Vrain_CC_1	PSCo	297	CC	NGA	7.591
	Ft_St_Vrain_CC_2	PSCo	128	CC	NGA	7.662
	Ft_St_Vrain_CC_3	PSCo	131	CC	NGA	7.558
	Ft_St_Vrain_CC_4	PSCo	135	CC	NGA	7.556
	Front_Range_1a	IPP	132	CC	NGA	7.274
	Front_Range_1b	IPP	133	CC	NGA	7.274
	Front_Range_1c	IPP	196	CC	NGA	7.274
	Rocky_Mtn_EC_1a	IPP	143	CC	NGA	7.274
	Rocky_Mtn_EC_1b	IPP	143	CC	NGA	7.274
	Rocky_Mtn_EC_1c	IPP	322	CC	NGA	7.274
			1760			**7.398**

APPENDIX A: (CONT.)

List of Colorado Installed Capacity - Base-Year (2005) Cont.,						
Technology Type	Plant Name	Owner	Capacity (MW)	Type	Fuel Type	Heat Rate (mmBTu/MWh)
	Manchief_1	IPP	132	CT	NGA	10.953
	Manchief_2	IPP	132	CT	NGA	10.953
	Arapahoe_5	IPP	39	CT	NGA	9.960
	Arapahoe_6	IPP	39	CT	NGA	9.960
	Arapahoe_7	IPP	45	CT	NGA	9.960
	Blue_Spruce_1	IPP	138	CT	NGA	10.587
	Blue_Spruce_2	IPP	138	CT	NGA	10.587
	CPP_Brush	IPP	68	CT	NGA	8.650
	Brush_4D	IPP	130	CT	NGA	9.960
	Limon_1	TSGT	67	CT	NGA	12.269
	Limon_2	TSGT	67	CT	NGA	12.269
	Frank Knutson_1	TSGT	67	CT	NGA	12.797
	Frank Knutson_2	TSGT	67	CT	NGA	12.797
	Plains_End_1	IPP	113	CT	NGA	9.580
	Fountain_Valley_GT_1-6	IPP	236	CC	NGA	10.685
	Ft_Lupton_GT_1	PSCo	50	CT	NGA	10.316
	Ft_Lupton_GT_2	PSCo	50	CT	NGA	15.500
	Martin_Drake_1	CSU	5	CT	NGA	12.560
	Martin_Drake_3	CSU	5	CT	NGA	12.150
	Martin_Drake_4	CSU	11	CT	NGA	12.100
	Rawhide_A1	PRPA	60	CT	NGA	15.049
	Rawhide_B2	PRPA	60	CT	NGA	15.049
	Rawhide_C3	PRPA	60	CT	NGA	15.049
	Rawhide_E4	PRPA	66	CT	NGA	15.049
	Rifle_1	IPP	68	CC	NGA	11.860
	Nixon_GT_1	CSU	30	CT	NGA	17.512
	Nixon_GT_2	CSU	30	CT	NGA	17.512
	Thermo_Ind	IPP	129	CT	NGA	9.400
	Thermo_Carb	IPP	150	CT	NGA	9.400
	Thermo_Greeley	IPP	32	CT	NGA	9.700
	Thermo_UNC	IPP	69	CT	NGA	8.650
	CU_Cogen	IPP	31	CT	NGA	8.428
	Valmont_7	IPP	41	CT	NGA	10.668
	Valmont_8	IPP	41	CT	NGA	10.668
			2466			**11.215**
	Alamosa_GT_1	PSCo	12	CT	NGA	14.450
	Alamosa_GT_2	PSCo	14	CT	NGA	15.467
	Birdsall_1	CSU	16	CT	NGA	14.500
	Birdsall_2	CSU	17	CT	NGA	14.500
	Birdsall_3	CSU	23	CT	NGA	14.500
	Brighton_1	PSCo	50	CT	NGA	16.318
	Brighton_2	PSCo	50	CT	NGA	16.318
	Fruita_GT	PSCo	15	CT	NGA	14.992
	Puebl_6	WPE	28	CT	NGA	14.500
	Cherokee_Dies	PSCo	6	CT	DSL	14.500
	Bullock	PSCo	12	IC	DSL	14.500
	Delta_IC	TSGT	5	IC	DSL	14.500
	WPE_Diesel_IC	WPE	18	IC	DSL	14.500
	Rocky_Ford	TSGT	10	IC	DSL	15.806
			276			

APPENDIX A: (CONT.)

List of Colorado Installed Capacity - Base-Year (2005) Cont.,		
Technology Type	**Plant Name**	**Capacity (MW)**
	Agregate Fossil Plants	
	Coal_ST_Bit	1733
	Coal_ST_Sub_Bit	3410
	Total Coal	**5143**
	NGA_ST	107
	NGA_CC	1760
	NGA_CT	2466
	Total NGA	**4333**
	NGA/DSL_CT/IC Total	**276**
	Total (Fossil Fuel)	**9,752**
Hydro	Foothills Hydro Plant	3.1
	Strontia Springs Hydro Plant	1
	Dillon Hydro Plant	1.8
	Williams Fork Hydro Plant	3
	North Fork Hydro Plant	5.5
	Boulder Canyon Hydro	5
	Georgetown	0.8
	Georgetown	0.8
	Palisade	1.6
	Palisade	1.6
	Salida	0.8
	Salida	0.6
	Shoshone	7.5
	Shoshone	7.5
	Manitou Springs	2.5
	Manitou Springs	2.5
	Ruxton Park	1
	Vallecito Hydroelectric	0.4
	Vallecito Hydroelectric	2.5
	Vallecito Hydroelectric	2.5
	Redlands Water & Power	0.6
	Sugarloaf Hydro Plant	2.5
	Blue Mesa	43.2
	Blue Mesa	43.2
	Estes	17.2
	Estes	17.2
	Estes	17.2
	Morrow Point	86.6
	Morrow Point	86.6
	Big Thompson	5.2

APPENDIX A:..(CONT.)

List of Colorado Installed Capacity - Base-Year (2005) Cont.,

Technology Type	Plant Name	Capacity (MW)
	Green Mountain	13
	Green Mountain	13
	Marys Lake	9.3
	Flatiron	43
	Flatiron	43
	Pole Hill	38.2
	Lower Molina	4.8
	Upper Molina	8.6
	Hillcrest Pump Station	2
	Boulder City Lakewood Hydro	3.5
	Boulder City Betasso Hydro	3
	Taylor Draw Hydro Facility	2
	Boulder City Silver Lake Hydro	3.3
	Crystal	30
	Tacoma	2.2
	Tacoma	2.2
	Tacoma	4
	Ames Hydro	3.7
	Tesla	25
	McPhee	1.2
	Towaoc	11.4
	Ruedi	5
	Total Colorado Hydro	**642.9**
	Cabin Creek	162
	Cabin Creek	162
	Flatiron	8.5
	Mount Elbert	115
	Mount Elbert	115
	Total Pump-Storage	**562.5**
Wind	Lamar Plant	4
	Lamar Plant	1.5
	Ponnequin Phase 1	5.2
	Ridge Crest Wind Partners	7.55
	Colorado Green Holdings LLC	162
	Ponnequin	9
	Ponnequin	15.4
	Spring Canyon	60
	Total Colorado Wind	**264.65**
MSW	Metro Wastewater District	**9.8**
	Total (Non-Fossil Fuel)	**1,480**
	Total Colorado	**11,232**

APPENDIX B: EXISTING POWER PLANTS EMISSION FACTORS

Colorado Fossil-Fueled Electric Generation Emissions (2006)

Plant Name	Company	Total Operating Hours	Fuel Type	Cumulative Annual Heat Input (mmBtu)	Cumulative Annual SO2 Emissions (tons)	Cumulative Annual CO2 Emissions (tons)	Cumulative Annual NOx Emissions (tons)	Average SO2 Emission Rate (lb/mmBtu)	Average CO2 Emission Rate (lb/mmBtu)	Average NOx Emission Rate (lb/mmBtu)	Max. Capacity (MW)	Wt. Average	Heat Rate (Btu/kWh)	Average SO2 Emission Rate (kt/PJ)	Average CO2 Emission Rate (kt/PJ)	Average NOx Emission Rate (kt/PJ)
Coal Units																
Cameo 2	PSCo	8,512.41	Bituminous	4,098,192	2,108.1	420,473.6	731.5	1.029	205.2	0.357	54	0.03	10,994	1.4248	284	0.4944
Cherokee 1	PSCo	7,705.34	Bituminous	8,154,761	2,165.2	834,944.2	1,439.6	0.531	204.8	0.353	115	0.07	10,807	0.7229	279	0.4806
Cherokee 2	PSCo	8,426.23	Bituminous	9,681,982	2,442.1	992,304.9	3,383.5	0.504	205.0	0.699	120	0.07	10,470	0.6853	270	0.9218
Cherokee 3	PSCo	7,300.16	Bituminous	10,756,231	704.0	1,100,486.7	1,820.3	0.131	204.6	0.338	165	0.10	10,145	0.1673	261	0.4325
Cherokee 4	PSCo	8,013.12	Bituminous	27,246,266	1,749.9	2,788,504.5	4,157.6	0.128	204.7	0.305	386	0.24	9,532	0.1542	246	0.3664
Hayden 1	PSCo	8,522.11	Bituminous	19,317,348	1,297.6	1,981,982.4	4,094.5	0.134	205.2	0.424	205	0.12	10,357	0.1753	268	0.5531
Hayden 2	PSCo	8,332.07	Bituminous	24,238,730	1,593.5	2,486,889.9	3,981.3	0.131	205.2	0.329	300	0.18	12,248	0.2029	317	0.5068
Nucla	TSGT	8,125.76	Bituminous	9,325,961	1,401.7	957,535.7	1,921.7	0.301	205.3	0.412	100	0.06	11,827	0.4478	306	0.6140
Valmont	PSCo	8,659.95	Bituminous	15,810,832	876.7	1,622,190.9	2,514.1	0.111	205.2	0.318	189	0.12	9,391	0.1315	243	0.3762
Bit. Coal Capacity					**14,341**	**13,185,293**	**24,044**				**1646**	**0.33**	**10,519**	**0.3008**	**272**	**0.4908**
Arapahoe 3	PSCo	7,826.34	Subbituminous	3,768,829	940.1	386,678.8	1,446.7	0.499	205.2	0.768	47	0.01	11,608	0.742	305	1.142
Arapahoe 4	PSCo	7,125.94	Subbituminous	7,591,624	1,471.5	778,898.0	889.7	0.388	205.2	0.234	121	0.04	11,251	0.549	291	0.332
Comanche 1	PSCo	8,017.30	Subbituminous	25,653,046	6,613.0	2,628,704.3	4,057.8	0.516	204.9	0.316	366	0.11	10,453	0.679	270	0.417
Comanche 2	PSCo	7,070.12	Subbituminous	25,533,282	6,829.6	2,614,086.8	3,913.5	0.535	204.8	0.307	370	0.11	10,470	0.706	270	0.404
Craig 1	TSG	8,662.33	Subbituminous	41,629,869	1,057.4	4,271,224.2	5,823.5	0.051	205.2	0.280	428	0.13	10,307	0.066	266	0.363
Craig 2	TSGT	8,372.43	Subbituminous	39,421,782	1,008.3	4,044,673.2	5,415.5	0.051	205.2	0.275	428	0.13	10,423	0.067	269	0.361
Craig 3	TSGT	7,616.15	Subbituminous	31,899,039	2,010.1	3,272,837.4	6,467.7	0.126	205.2	0.406	408	0.12	10,155	0.161	262	0.519
Pawnee	PSCo	7,166.36	Subbituminous	34,507,189	11,248.1	3,532,021.5	3,668.1	0.652	204.7	0.213	505	0.15	10,430	0.857	269	0.279
Martin Drake 5	CSU	7,563.25	Subbituminous	3,656,664	1,340.3	374,834.4	768.2	0.733	205.0	0.420	47	0.01	11,678	1.078	302	0.618
Martin Drake 6	CSU	8,380.25	Subbituminous	7,411,277	2,930.0	759,939.0	1,408.3	0.791	205.1	0.380	79	0.02	11,182	1.114	289	0.535
Martin Drake 7	CSU	8,759.50	Subbituminous	12,597,145	4,894.1	1,291,527.2	2,767.9	0.777	205.1	0.439	133	0.04	10,427	1.021	269	0.577
Rawhide	PRPA	7,515.73	Subbituminous	22,783,530	875.5	2,337,590.1	3,729.1	0.077	205.2	0.327	270	0.08	10,415	0.101	269	0.429
Ray D Nixon	CSU	7,637.75	Subbituminous	16,644,908	3,750.8	1,707,111.4	2,168.1	0.451	205.1	0.261	208	0.06	10,492	0.596	271	0.344
Sub-Bit. Coal Capacity					**44,969**	**28,000,124**	**42,524**				**3410**	**0.67**	**10,473**	**0.4868**	**270**	**0.4088**
Coal Capacity & Pollution					**59,310**	**41,185,417**	**66,568**				**5056**					
Gas Units																
Combined Cycles																
Fort St. Vrain 2	PSCo	8,223.15	NGA	10,745,839	3.2	636,609.2	161.2	0.001	118.9	0.030	204	0.12	7591	0.001	114	0.029
Fort St. Vrain 3	PSCo	8,194.75	NGA	10,989,786	3.4	653,102.7	146.9	0.001	118.9	0.027	259	0.15	7662	0.001	115	0.026
Fort St. Vrain 4	PSCo	8,188.17	NGA	10,936,164	3.2	649,922.3	78.3	0.001	118.9	0.014	228	0.13	7556	0.001	113	0.014
Front Range 1	Fring/PSCo	5,771.81	NGA	7,441,860	2.3	442,258.8	114.7	0.001	118.9	0.031	231	0.13	7274	0.001	109	0.028
Front Range 2	Fring/PSCo	6,205.25	NGA	7,971,870	2.4	473,755.7	143.6	0.001	118.9	0.036	231	0.13	7274	0.001	109	0.033
Rocky Mountain CT1	Fring/PSCo	6,970.25	NGA	11,695,800	3.6	695,068.6	46.8	0.001	118.9	0.008	304	0.17	7274	0.001	109	0.007
Rocky Mountain CT2	Fring/PSCo	7,651.50	NGA	12,753,240	3.7	757,914.7	46.0	0.001	118.9	0.007	304	0.17	7274	0.001	109	0.007
					21.8	**4,310,632.0**	**737.5**				**1761**		**7,404**	**0.0006**	**111**	**0.0193**
Steam																
Zuni 1	PSCo	3,303.91	NGA	441,259	0.1	26,228.5	45.4	0.000	118.9	0.206	39	0.36	13387	0.001	200	0.347
Zuni 2	PSCo	160.13	NGA	21,696	0.0	1,289.6	1.8	0.000	118.9	0.166	68	0.64	13387	0.000	200	0.280
					0	**27,518**	**47**				**107**		**13,387**	**0.0005**	**252**	**0.3110**

APPENDIX B: (Cont.)

Plant Name	Company	Total Operating Hours	Fuel Type	Cumulative Annual Heat Input (mmBtu)	Cumulative Annual SO2 Emissions (tons)	Cumulative Annual CO2 Emissions (tons)	Cumulative Annual NOx Emissions (tons)	Average SO2 Emission Rate (lb/mmBtu)	Average CO2 Emission Rate (lb/mmBtu)	Average NOx Emission Rate (lb/mmBtu)	Max. Capacity (MW)	Wt. Average	Heat Rate (Btu/kWh)	Average SO2 Emission Rate (kt/PJ)	Average CO2 Emission Rate (kt/PJ)	Average NOx Emission Rate (kt/PJ)
Combustion Turbines																
Arapahoe CT5	Frng/PSCo	3,153.10	NGA	1,042,518	0.4	61,955.4	12.0	0.001	118.9	0.023	39	0.02	9960	0.001	149	0.029
Arapahoe CT6	Frng/PSCo	3,132.09	NGA	1,072,006	0.4	63,707.2	11.6	0.001	118.9	0.022	39	0.02	9960	0.001	149	0.028
Arapahoe CT7	Frng/PSCo	3,132.09	NGA	1,072,006	0.4	63,707.2	11.6	0.001	118.9	0.022	45	0.03	9960	0.001	149	0.028
Blue Spruce CT1	Frng/PSCo	1,280.41	NGA	1,703,715	1.2	101,468.3	28.8	0.001	119.1	0.034	138	0.08	10587	0.002	159	0.045
Blue Spruce CT2	Frng/PSCo	873.66	NGA	1,208,088	2.8	72,401.8	22.2	0.005	120.1	0.037	138	0.08	10587	0.006	160	0.049
Brush 3 GT2	Frng/PSCo	16.31	NGA	7,216	0.0	428.9	0.4	0.000	118.9	0.111	68	0.04	8650	0.000	130	0.121
Brush 4 GT4	Frng/PSCo	302.88	NGA	139,805	0.0	8,308.7	0.0	0.000	118.9	0.000	65	0.04	9960	0.000	149	0.000
Brush 4 GT5	Frng/PSCo	270.89	NGA	131,199	0.0	7,796.6	0.0	0.000	118.9	0.000	65	0.04	9960	0.000	149	0.000
Fountain Valley CT1	Frng/PSCo	2,211.75	NGA	619,127	0.1	36,793.0	31.8	0.000	118.9	0.103	39	0.02	10685	0.000	160	0.138
Fountain Valley CT2	Frng/PSCo	1,473.50	NGA	451,230	0.1	26,815.1	21.3	0.000	118.9	0.094	39	0.02	10685	0.001	160	0.127
Fountain Valley CT3	Frng/PSCo	2,126.50	NGA	616,521	0.1	36,639.0	30.5	0.000	118.9	0.099	39	0.02	10685	0.000	160	0.133
Fountain Valley CT4	Frng/PSCo	1,360.00	NGA	397,994	0.1	23,651.9	19.3	0.001	118.9	0.097	39	0.02	10685	0.001	160	0.131
Fountain Valley CT5	Frng/PSCo	1,608.50	NGA	511,665	0.1	30,406.7	26.7	0.000	118.9	0.104	39	0.02	10685	0.001	160	0.140
Fountain Valley CT6	Frng/PSCo	1,301.25	NGA	382,015	0.1	22,703.8	18.5	0.001	118.9	0.097	39	0.02	10685	0.001	160	0.130
Frank Knutson BR1	TSG	228.25	NGA	151,013	0.0	8,975.7	2.3	0.000	118.9	0.030	67	0.04	12797	0.000	192	0.049
Frank Knutson BR2	TSG	191.25	NGA	130,815	0.0	7,774.2	1.6	0.000	118.9	0.024	67	0.04	12797	0.000	192	0.039
Limon L1	TSG	202.25	NGA	141,101	0.0	8,385.2	1.9	0.000	118.9	0.027	67	0.04	12269	0.000	184	0.042
Limon L2	TSG	181.00	NGA	136,093	0.0	8,092.9	1.9	0.000	118.9	0.028	67	0.04	12269	0.000	184	0.043
Manchief CT1	Frng/PSCo	392.00	NGA	438,137	0.1	26,037.9	13.1	0.000	118.9	0.060	132	0.08	10953	0.001	164	0.083
Manchief CT2	Frng/PSCo	448.00	NGA	471,952	0.1	28,069.4	14.1	0.000	119.0	0.060	132	0.08	10953	0.001	164	0.082
Rawhide CT A	PRPA	56.98	NGA	40,076	0.0	2,381.7	0.8	0.000	118.9	0.040	60	0.03	15049	0.000	225	0.076
Rawhide CT B	PRPA	155.12	NGA	106,730	0.0	6,342.6	1.7	0.000	118.9	0.032	60	0.03	15049	0.000	225	0.060
Rawhide CT C	PRPA	109.81	NGA	76,792	0.0	4,563.2	1.2	0.000	118.8	0.031	60	0.03	15049	0.000	225	0.059
Rawhide CT D	PRPA	52.32	NGA	35,588	0.0	2,115.2	0.6	0.000	118.9	0.034	66	0.04	15049	0.000	225	0.064
Ray D Nixon CT 2	CSU	96.25	NGA	25,444	0.0	1,512.4	0.6	0.000	118.9	0.047	30	0.02	17512	0.000	262	0.104
Ray D Nixon CT 3	CSU	54.50	NGA	14,741	0.0	876.3	0.3	0.000	118.9	0.041	30	0.02	17512	0.000	262	0.090
Valmont CT7	Frng/PSCo	89.22	NGA	24,907	0.0	1,480.5	1.4	0.000	118.9	0.112	41	0.02	10668	0.000	160	0.151
Valmont CT8	Frng/PSCo	103.89	NGA	29,417	0.0	1,748.6	1.4	0.000	118.9	0.095	41	0.02	10668	0.000	160	0.128
					6	**868,139**	**278**				**1761**			**0.0009**	**176**	**0.0716**
Tons					**59,338**	**46,188,707**	**67,631**									
Metric Tonne					**53,943**	**41,969,733**	**61,483**									

APPENDIX C: MODEL INPUT ASSUMPTIONS AND RESOURCE BOUNDS

Technology Investment Cost

Technology ($/kw)	2005	2008	2011	2014	2017	2020	2023	2026	2029	2032	2035
Biomass_CC		3313.0	3313.0	3302.0	3302.0	3280.0	3302.0	3258.0	3231.0	3255.0	3255.0
PC_Coal_CCS	3769.0	3769.0	3769.0	3769.0	3769.0	3769.0	3769.0	3769.0	3769.0	3769.0	3769.0
Com3_Xcel		2020.0	2020.0	2020.0	2020.0	2020.0	2020.0	2020.0	2020.0	2020.0	2020.0
IGCC_Xcel			4008.0	4008.0	4008.0	4008.0	4008.0	4008.0	4008.0	4008.0	4008.0
Geothermal		3641.0	3641.0	3641.0	3641.0	3641.0	3641.0	3641.0	3641.0	3641.0	3641.0
IGCC_CCS			4008.0	4008.0	4008.0	4008.0	4008.0	4008.0	4008.0	4008.0	4008.0
Adv_CT			519.6	519.6	519.6	519.6	519.6	519.6	519.6	519.6	519.6
Adv_CC			827.0	827.0	827.0	827.0	827.0	827.0	827.0	827.0	827.0
CC		885.0	885.0	885.0	885.0	885.0	885.0	885.0	885.0	885.0	885.0
CT		659.0	659.0	659.0	659.0	659.0	659.0	659.0	659.0	659.0	659.0
Gas_IGCC_CCS			1124.0	1124.0	1124.0	1124.0	1124.0	1124.0	1124.0	1124.0	1124.0
Adv_Nuclear			2897.0	2897.0	2897.0	2897.0	2897.0	2897.0	2897.0	2897.0	2897.0
PV_Central		3830.0	3793.0	3593.0	2941.0	2941.0	2941.0	2941.0	2941.0	2941.0	2941.0
PV_Rooftop		7519.1	6379.5	5239.9	4565.6	3891.2	3891.2	3891.2	3891.2	3891.2	3891.2
Solar_Thermal		2539.0	2466.0	2348.0	2348.0	2106.0	2106.0	2106.0	2106.0	2106.0	2106.0
Wind	1690.0	1690.0	1690.0	1690.0	1690.0	1690.0	1690.0	1690.0	1690.0	1690.0	1690.0

Notes:

CC = Combined Cycle

CT = Combustion Turbine

PC = Pulverized Coal

IGCC = Integrated Gasification Combined Cycle

Com3 = Pulverized coal unit by Xcel Energy

APPENDIX C: (Cont.)

Variable O&M Costs

Technology ($/GJ)	2005	2008	2011	2014	2017	2020	2023	2026	2029	2032	2035
New Biomass CC	0	14.94	14.94	15.67	16.43	16.82	17.77	18.13	18.71	18.73	18.73
Muni Solid Waste	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003	0.003
New PC with CCS	2.9389	2.9389	2.9389	2.9389	2.9389	2.9389	2.9389	2.9389	2.9389	2.9389	2.9389
Com3 Xcel	0.8493	0.8493	0.8493	0.8493	0.8493	0.8493	0.8493	0.8493	0.8493	0.8493	0.8493
IGCC Xcel	0.8472	0.8472	0.8472	0.8472	0.8472	0.8472	0.8472	0.8472	0.8472	0.8472	0.8472
Co-Fire	0.7714	0.7714	0.7714	0.7714	0.7714	0.7714	0.7714	0.7714	0.7714	0.7714	0.7714
Bit Coal Steam	0.7714	0.7714	0.7714	0.7714	0.7714	0.7714	0.7714	0.7714	0.7714	0.7714	0.7714
Sub Bit Coal Steam	0.7714	0.7714	0.7714	0.7714	0.7714	0.7714	0.7714	0.7714	0.7714	0.7714	0.7714
DSF Steam	0.1458	0.1458	0.1458	0.1458	0.1458	0.1458	0.1458	0.1458	0.1458	0.1458	0.1458
Diesel IC	2.4684	2.4684	2.4684	2.4684	2.4684	2.4684	2.4684	2.4684	2.4684	2.4684	2.4684
New Geothermal		6.3556	6.3556	6.3556	6.3556	6.3556	6.3556	6.3556	6.3556	6.3556	6.3556
Hydro	1.2455	1.2455	1.2455	1.2455	1.2455	1.2455	1.2455	1.2455	1.2455	1.2455	1.2455
Hydro PS	0.7349	0.7349	0.7349	0.7349	0.7349	0.7349	0.7349	0.7349	0.7349	0.7349	0.7349
New Coal IGCC			0.8472	0.8472	0.8472	0.8472	0.8472	0.8472	0.8472	0.8472	0.8472
New Adv CT			0.7859	0.7859	0.7859	0.7859	0.7859	0.7859	0.7859	0.7859	0.7859
New Adv CC			0.8583	0.8583	0.8583	0.8583	0.8583	0.8583	0.8583	0.8583	0.8583
CC	0.1359	0.1359	0.1359	0.1359	0.1359	0.1359	0.1359	0.1359	0.1359	0.1359	0.1359
New CC		0.7806	0.7806	0.7806	0.7806	0.7806	0.7806	0.7806	0.7806	0.7806	0.7806
CT	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029	0.029
New CT		2.2086	2.2086	2.2086	2.2086	2.2086	2.2086	2.2086	2.2086	2.2086	2.2086
New Gas IGCC			0.8147	0.8147	0.8147	0.8147	0.8147	0.8147	0.8147	0.8147	0.8147
Gas Steam	0.1458	0.1458	0.1458	0.1458	0.1458	0.1458	0.1458	0.1458	0.1458	0.1458	0.1458
New Adv Nuclear	0.1667	0.1667	0.1667	0.1667	0.1667	0.1667	0.1667	0.1667	0.1667	0.1667	0.1667
PV_Central		0	0	0	0	0	0	0	0	0	0
PV_Rooftop		0	0	0	0	0	0	0	0	0	0
Solar_Thermal		0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0	0

Notes:
- $/GJ = 0.0036*$/KWh
- CC = Combined Cycle
- CT = Combustion Turbine
- PC = Pulverized Coal
- IGCC = Integrated Gasification Combined Cycle
- Com3 = Pulverized coal unit by Xcel Energy
- PS = Pumped Storage

Fixed O&M Costs

Technology ($/kW/yr)	2005	2008	2011	2014	2017	2020	2023	2026	2029	2032	2035
New Biomass CC		50.17	50.17	50.17	50.17	50.17	50.17	50.17	50.17	64.71	86.52
Muni Solid Waste	96.4781	96.4781	96.4781	96.4781	96.4781	96.4781	96.4781	96.4781	96.4781	96.4781	96.4781
New PC with CCS	46.2143	46.2143	46.2143	46.2143	46.2143	46.2143	46.2143	46.2143	46.2143	46.2143	46.2143
Com3 Xcel		15.6436	15.6436	15.6436	15.6436	15.6436	15.6436	15.6436	15.6436	15.6436	15.6436
IGCC Xcel					17.14	17.14	17.14	17.14	17.14	17.14	17.14
Co-Fire		15.6436	15.6436	15.6436	15.6436	15.6436	15.6436	15.6436	15.6436	15.6436	15.6436
Bit Coal Steam	15.6436	15.6436	15.6436	15.6436	15.6436	15.6436	15.6436	15.6436	15.6436	15.6436	15.6436
Sub Bit Coal Steam	15.6436	15.6436	15.6436	15.6436	15.6436	15.6436	15.6436	15.6436	15.6436	15.6436	15.6436
DSF Steam	0.861	0.861	0.861	0.861	0.861	0.861	0.861	0.861	0.861	0.861	0.861
Diesel IC	0.861	0.861	0.861	0.861	0.861	0.861	0.861	0.861	0.861	0.861	0.861
New Geothermal		0	0	0	0	0	0	0	0	0	0
Hydro	14.2025	14.2025	14.2025	14.2025	14.2025	14.2025	14.2025	14.2025	14.2025	14.2025	14.2025
Hydro PS	16.7088	16.7088	16.7088	16.7088	16.7088	16.7088	16.7088	16.7088	16.7088	16.7088	16.7088
New Coal IGCC			17.14	17.14	17.14	17.14	17.14	17.14	17.14	17.14	17.14
New Adv CT			8.8871	8.8871	8.8871	8.8871	8.8871	8.8871	8.8871	8.8871	8.8871
New Adv CC			9.4173	9.4173	9.4173	9.4173	9.4173	9.4173	9.4173	9.4173	9.4173
CC	15.7508	15.7508	15.7508	15.7508	15.7508	15.7508	15.7508	15.7508	15.7508	15.7508	15.7508
New CC		13.193	13.193	13.193	13.193	13.193	13.193	13.193	13.193	13.193	13.193
CT	6.5109	6.5109	6.5109	6.5109	6.5109	6.5109	6.5109	6.5109	6.5109	6.5109	6.5109
New CT		4.3137	4.3137	4.3137	4.3137	4.3137	4.3137	4.3137	4.3137	4.3137	4.3137
New Gas IGCC			19.9501	19.9501	19.9501	19.9501	19.9501	19.9501	19.9501	19.9501	19.9501
Gas Steam	0.861	0.861	0.861	0.861	0.861	0.861	0.861	0.861	0.861	0.861	0.861
New Adv Nuclear	58	58	58	58	58	58	58	58	58	58	58
PV_Central		8.9648	8.9648	8.9648	8.9648	8.9648	8.9648	8.9648	8.9648	8.9648	8.9648
PV_Rooftop		0	0	0	0	0	0	0	0	0	0
Solar_Thermal		43.5494	43.5494	43.5494	43.5494	43.5494	43.5494	43.5494	43.5494	43.5494	43.5494
Wind	23.2443	23.2443	23.2443	23.2443	23.2443	23.2443	23.2443	23.2443	23.2443	23.2443	23.2443

Notes:
CC = Combined Cycle
CT = Combustion Turbine
PC = Pulverized Coal
IGCC = Integrated Gasification Combined Cycle
Com3 = Pulverized coal unit by Xcel Energy
PS = Pumped Storage

APPENDIX C: (Cont.)

Technology Heat Rate

Technology	Fuel	Heat Rate (PJ/PJ)	Heat Rate (Btu/kWh)
Biomass CC	Biomass	3.013	10,283
Muni Solid Waste	Solid Waste	3.791	12,939
New PC with CCS	Sub_Bit Coal	3.324	11,343
Com3 Xcel	Sub_Bit Coal	2.541	8,672
IGCC Xcel	Sub_Bit Coal	2.989	10,202
Co-Fire	Bit Coal & Biomass	3.111	10,618
Bit Coal Steam	Bit Coal	3.111	10,618
Sub Bit Coal Steam	Sub_Bit Coal	3.069	10,474
Disstilate Fuel Oil	Distillate Fuel Oil	3.784	12,916
Diesel IC	Diesel	3.784	12,916
Geothermal	Geothermal	3.013	10,283
Hydro	HYDRO	3.013	10,283
Hydro PS	Electricity	1.100	3,754
New Coal IGCC	Sub Bit Coal	2.989	10,202
New Adv CT	Natural Gas	2.506	8,553
New Adv CC	Natural Gas	2.133	7,281
Existing Gas CC	Natural Gas	2.168	7,399
New CC	Natural Gas	2.187	7,463
Existing Gas CT	Natural Gas	3.084	10,525
New CT	Natural Gas	3.065	10,459
New Gas IGCC	Natural Gas	2.330	7,952
Existing Gas Steam	Natural Gas	3.923	13,390
New Adv Nuclear	Nuclear	3.080	10,512
PV_Central	Solar	3.013	10,283
PV_Rooftop	Solar	3.013	10,283
Solar_Thermal	Solar	3.013	10,283
Wind	Wind	3.013	10,283

Notes:
CC = Combined Cycle
CT = Combustion Turbine
IC = Internal Combustion
PC = Pulverized Coal
IGCC = Integrated Gasification Combined Cycle
Com3 = Pulverized coal unit by Xcel Energy
PS = Pumped Storage

APPENDIX C: (Cont.)

Fuel Cost

Fuel Type ($/GJ)	2005	2008	2011	2014	2017	2020	2023	2026	2029	2032	2035
Sub_Bit Coal	1.00	1.05	1.10	1.13	1.15	1.18	1.21	1.25	1.30	1.35	1.40
Disstilate Fuel Oil	5.24	7.42	7.26	6.55	6.47	6.56	6.74	6.88	7.10	7.11	7.22
Diesel	6.68	9.70	9.83	9.07	9.07	9.32	9.65	9.98	10.03	9.87	9.86
Coal Base Imports	11.11	12.50	13.89	14.30	14.72	16.11	18.06	21.11	23.34	25.56	27.22
Gas Based Imports	16.67	18.89	20.56	19.45	20.84	22.22	25.00	28.33	32.78	36.11	38.41
High Gas Based Imports	16.67	28.90	41.12	38.90	41.68	44.44	50.00	56.66	65.56	72.22	76.82
Mod Gas Based Imports	16.67	23.76	30.84	29.18	31.26	33.33	37.50	42.50	49.17	54.17	57.62
Natural Gas Step 1	7.95	7.50	6.80	6.50	7.50	8.00	8.50	9.50	10.20	11.00	12.20
High_Gas Step 1	7.95	10.78	13.60	13.00	15.00	16.00	17.00	19.00	20.40	22.00	24.40
Mod_Gas Step 1	7.95	9.08	10.20	9.75	11.25	12.00	12.75	14.25	15.30	16.50	18.30
Nuclear	0.46	0.60	1.00	1.20	1.15	1.17	1.21	1.25	1.30	1.37	1.40
Biomass Step1	2.13	2.23	2.33	2.44	2.55	2.67	2.79	2.92	3.05	3.19	3.33
Biomass Step2	2.13	2.23	2.33	2.44	2.55	2.67	2.79	2.92	3.05	3.19	3.33
Bit_Coal	1.00	1.05	1.10	1.13	1.15	1.18	1.21	1.25	1.30	1.35	1.40
Muni_Solid Waste	1.00	1.02	1.03	1.05	1.06	1.08	1.09	1.11	1.13	1.14	1.16
Natural Gas Step 2	7.95	7.50	6.80	6.50	7.50	8.00	8.50	9.50	10.20	11.00	12.20
High_Gas Step2	7.95	10.78	13.60	13.00	15.00	16.00	17.00	19.00	20.40	22.00	24.40
Mod_Gas Step2	7.95	9.08	10.20	9.75	11.25	12.00	12.75	14.25	15.30	16.50	18.30

Notes:
$/GJ = 0.948*$/mmBtu

APPENDIX C: (Cont.)

Emission Rates – Output Rate (at the production level)

Technology	CO2 (lb/MWh) Output	NOx (lb/MWh) Output	SO2 (lb/MWh) Output
PC_Coal 50% CCS	1,167	0.373	0.619
Com3_Xcel	2,159	0.000	0.000
IGCC_Xcel	1,048	0.427	0.705
Bit Coal Steam	2,159	3.895	2.387
Sub Bit Coal Steam	2,143	3.181	3.705
Disstilate Fuel Oil	2,000	2.468	0.195
Diesel IC	2,000	2.468	0.195
Coal_IGCC 50%CCS	1,048	0.429	0.706
Adv CT	921	0.087	
Adv CC	865	0.071	
CC	881	0.153	
New CC	889	0.341	
CT	1,278	0.568	
New CT	1,246	0.517	
Gas IGCC 90% CCS	86	0.079	
Gas Steam	1,587	2.415	
Coal Based Imports	2,159		
Gas Based Imports	881		

Notes:
CC = Combined Cycle
CT = Combustion Turbine
IC = Internal Combustion
PC = Pulverized Coal
IGCC = Integrated Gasification Combined Cycle
Com3 = Pulverized coal unit by Xcel Energy

APPENDIX C: (Cont.)

Power Import Bounds

Import (Gwh/yr)	Bound	2005	2008	2011	2014	2017	2020	2023	2026	2029	2032	2035
Coal Utility Contracts	FX	444.4	444.4	444.4	444.4							
Coal Based	UP	1416.7	1416.7	1416.7	1416.7	1416.7	1416.7	1416.7	1416.7	1416.7	1416.7	1416.7
Gas Based	UP	1416.7	1416.7	1416.7	1416.7	1416.7	1416.7	1416.7	1416.7	1416.7	1416.7	1416.7
Hydro	UP	0	0	0	0	0	0	0	0	0	0	0
Renewable	UP	0	0	0	0	0	0	0	0	0	0	0

Note: Fixed bound is for utility fixed (take or pay) contacts

Investment Bounds

Technology	Unit	Investment Bound	2005	2008	2011	2014	2017	2020	2023	2026	2029	2032	2035
New Biomass CC	GW	UP		0.1									0.44
Existing Muni Solid Waste	GW	UP	0	0	0	0	0	0	0	0	0	0	0
Com3 Xcel	GW	FX	0	0	0.75	0	0	0	0	0	0	0	0
IGCC Xcel	GW	FX	0	0	0	0	0.6	0	0	0	0	0	0
Existing Bit Coal Steam	GW	UP	0	0	0	0	0	0	0	0	0	0	0
Existing Sub Bit Coal Steam	GW	UP	0	0	0	0	0	0	0	0	0	0	0
Existing Disstilate Fuel Oil	GW	UP	0	0	0	0	0	0	0	0	0	0	0
Existing Diesel IC	GW	UP	0	0	0	0	0	0	0	0	0	0	0
New Geothermal	GW	UP		0.03									0.04
Existing Hydro	GW	UP	0	0	0	0	0	0	0	0	0	0	0
Existing Hydro PS	GW	UP	0	0	0	0	0	0	0	0	0	0	0
Existing Gas_CC	GW	UP	0	0	0	0	0	0	0	0	0	0	0
Existing Gas_CT	GW	UP	0	0	0	0	0	0	0	0	0	0	0
Existing Gas_Steam	GW	UP	0	0	0	0	0	0	0	0	0	0	0
PV_Central	GW	LO		0.02									
PV_Rooftop	GW	LO		0.01									
Solar_Thermal	GW	UP				0.1							1
Wind	GW	UP	0	0.83									11

Notes:
- CC = Combined Cycle
- CT = Combustion Turbine
- PC = Pulverized Coal
- IGCC = Integrated Gasification Combined Cycle
- Com3 = Pulverized coal unit by Xcel Energy
- PS = Pumped Storage

APPENDIX C: (Cont.)

Energy Efficiency and DSM (Maximum Hour Marginal Avoided Costs)

Scenario	Technology ($/GJ/yr)	2008	2011	2014	2017	2020	2023	2026	2029	2032	2035
300 GWh/yr	Commercial	29.2	32.8	28.3	35.0	46.9	62.8	84.2	112.5	150.8	201.9
Xcel DSM	Commercial	29.2	32.8	28.3	35.0	46.9	62.8	84.2	112.5	150.8	201.9
Xcel Enh_DSM	Commercial	29.2	32.8	28.3	35.0	46.9	62.8	84.2	112.5	150.8	201.9
!% per yr EE	Commercial	29.2	32.8	28.3	35.0	46.9	62.8	84.2	112.5	150.8	201.9
300 GWh/yr	Industrial	29.2	32.8	28.3	35.0	46.9	62.8	84.2	112.5	150.8	201.9
!% per yr EE	Industrial	29.2	32.8	28.3	35.0	46.9	62.8	84.2	112.5	150.8	201.9
300 GWh/yr	Residential	29.2	32.8	28.3	35.0	46.9	62.8	84.2	112.5	150.8	201.9
Xcel DSM	Residential	29.2	32.8	28.3	35.0	46.9	62.8	84.2	112.5	150.8	201.9
Xcel Enh_DSM	Residential	29.2	32.8	28.3	35.0	46.9	62.8	84.2	112.5	150.8	201.9
!% per yr EE	Residential	29.2	32.8	28.3	35.0	46.9	62.8	84.2	112.5	150.8	201.9

APPENDIX C: (Cont.)

Renewables Growth Rates

Parameter	Technology	Value
GROWTH	Biomass	1.15
GROWTH	PV_Central	1.30
GROWTH	PV_Rooftop	1.30
GROWTH	Solar_Thermal	1.10
GROWTH	Wind	1.20

Parameter	Technology	Value
GROWTH_TID	Biomass	0.007
GROWTH_TID	PV_Central	0.100
GROWTH_TID	PV_Rooftop	0.025
GROWTH_TID	Solar_Thermal	0.100
GROWTH_TID	Wind	0.200

Notes:
Growth = Maximum annual growth rate in capacity
Growth_TID = Incremental capacity over and above growth constraint

APPENDIX C: (Cont.)

Technology Hurdle Rates and Global Discount Rate

Technology	Hurdle Rate
Biomass_CC	0.132
PC_Coal_CCS	0.162
Com3_Xcel	0.162
IGCC_Xcel	0.162
Geothermal	0.126
IGCC_CCS	0.162
Adv_CT	0.138
Adv_CC	0.154
CC	0.138
CT	0.138
Gas_IGCC_CCS	0.154
Adv_Nuclear	0.177
PV_Central	0.111
PV_Rooftop	0.111
Solar_Thermal	0.120
Wind	0.112
Global Discount Rate	0.075

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